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IN THE

United States Court of Appeals

FOR THE FIFTH CIRCUIT

No. 71-2761

On Petitions to Review Orders of the
Federal Power Commission

JOINT APPENDIX

(PART II)

SOUTHERN LOUISIANA AREA RATE CASE
PLACID OIL COMPANY, ET AL.,
Petitioners,

v.

FEDERAL POWER COMMISSION,
Respondent.

[4,567]

TESTIMONY OF JOHN C. JACOBS

* * * *

Q. Now, Mr. Jacobs, when the analysis is prepared for the AGA Reserve Report, you indicate that the subcommittee members actually do the work of reviewing the data, that subsequently the committee discusses their findings and ultimately you put all the different areas together to come up with a report. Is that in substance what is done?

A. In summary that is the procedure that the committee follows in preparing its annual report.

Q. Can you tell me, using South Louisiana as the example, how these eleven men actually go about getting their information?

A. Well, I have attempted to do that in the testimony

[4,568]

that was filed in writing.

Q. Well, let me be more specific, then, if I can. How would a producer—how would one of these men obtain information from Placid Oil Company, for example, as to whatever gas reserves have been proved in South Louisiana?

A. He would ask the Placid Oil Company for the information.

Q. Would he actually go to their offices?

A. He might very well go to their offices and look at the data there; copies of the data might be sent to him, might be loaned to him for his use in preparing the report.

Q. Now, if somebody in Placid Oil Company in charge of the data felt that the data was confidential, would this individual obtain that data?

A. As we have indicated in the report, we have some instances, which I have characterized as not having a significant effect upon the numbers that were published, in which data are withheld from the committee. Let's take a situation and let's suppose that Placid has drilled a well and because of the lease situation around this well he elects to hold that data confidential. And let's suppose further the committee member that has been assigned that particular field calls for the data and Placid says that this data will not be forthcoming from Placid. Well, then the committee goes to whatever sources of information may be available.

[4,569]

Q. You mean the subcommittee member?

A. Your correction stands. The subcommittee member would then look at whatever other sources of data might be available.

For example, the seismic information which shows the size of the structure is fairly generally available for Louisiana Offshore Area now. This wouldn't necessarily have to come from Placid.

There are other information that could come from wells being drilled by another operator in an adjoining lease. Whatever information of that type that were available would be collected by the subcommittee member.

The data as to reservoir pore space, that is, the recovery per acre-foot that is expected, in an area such as Offshore Louisiana where the sands from field to field in this characteristic don't differ too radically, might even be assumed in an initial estimate.

In other words, even though Placid said you cannot have these data now, there are situations in which the committee could obtain enough data to meet what it considers its minimum requirements and prepare an estimate for that particular field.

Q. Would the data which you have just described be sufficient to allow the subcommittee member to determine that there are proved reserves in an area where there is a well, the information about which he has none?

[4,570]

A. Well, as I have stated in my testimony, we are talking about proved reserves here, and a minimum requirement—one of the minimum requirements is that we have had a production test. In the case that I am citing, there would have had to have been production tests in some of these adjoining wells, at least one of them, in order to meet the minimum requirements.

Q. I see. So that if a well were drilled in a new field and you had no—the subcommittee had no information as to what that well showed, this would not be sufficient of itself to allow the reserves, if there were reserves, to be categorized as proved. Is that correct?

A. What I have tried to say is it might be and it might not be, depending upon the situation.

There are situations when it would not be, other situations when it would be.

Q. Mr. Jacobs, if a well were drilled again by, for example, Placid Oil Company in an area where there were no offsetting wells previously drilled and the subcommittee member had no information other than seismic and the other kind of information you have talked about, could you characterize that as proved reserves?

A. We could not.

Q. Mr. Jacobs, you indicated you were one of the founders of the Potential Gas Committee and are familiar

[4,571]

with the practices of it. Is that correct?

A. I have so testified.

Q. Yes.

A. Let me qualify that, if I may.

I, in describing my experience, pointed out that I was active in the Potential Gas Committee affairs for several years. I am not now, and have not been for the last couple of years.

Q. Under the approaches that the Potential Gas Committee uses, where would the well I have described hypothetically for Placid Oil—where would those reserves be found? Would they be probable, potential, speculative, or would they be any one of them?

A. Those reserves would be in the probable category the way these studies are made up.

Q. Using the definitions that are used by the Potential Gas Committee in their report, how can you arrive at that conclusion, Mr. Jacobs?

A. Well, I will correct my answer to say that in the case we are discussing, where there was drilling across the lease line, this Placid well would be in the probable category. If there were no across-the-lease-line drilling, it would be in the possible category.

* * * *

[4,572]

What I have tried to say in my written testimony is that it is of no consequence to the study, or to the calculation, the estimation of proved reserves, as to whether

a well is expendable or not. What the committee considers is every well that is drilled.

Now, there are no wells that are drilled in secret. Perhaps there is some misunderstanding about this. Perhaps there is some thought that because a well has the name expendable that it is done in secret and nobody knows anything about it. This, of course, is not so. Expendable wells have to be permitted the same as any other kind of well. And the

[4,573]

committee, one of the bits of data it works off of and that Mr. Bass did not emphasize in his testimony is the list of wells that are permitted. And all these expendable wells are permitted. So whether expendable or not, so far as the committee is concerned we consider all the wells that are drilled.

Q. Well, if a well were drilled as you define it as an expendable well from a device other than a permanent platform and it were drilled by Placid Oil Company, again for purposes of reference only, and capped and shut in and the data kept confidential, how would you on the American Gas Association Gas Reserve Committee treat the gas reserves under that?

A. The important thing to the committee, the factor in your question that affects the answer is the confidentiality of the data, regardless of whether the well is an expendable well or any other kind of a well. The question to the committee is whether or not the data are available to the committee.

Now, your question carries us back to what we talked about formerly. If the data on that particular well were held confidential, then the committee would search about and see if there were any other way in which it could

develop the minimum data that are necessary to prepare an estimate. If this were not so, it were impossible to prepare an estimate that year, then the well would be followed up next year—or the field would be followed up next year. And our experience has been

[4,574]

that in the greater part of these cases where people don't want to release data because of its proprietary value, that this is usually for a year, no longer.

Q. Mr. Jacobs, do your subcommittee members keep records to show which companies have kept information confidential and which have given data that they haven't considered confidential?

A. We do not keep such records.

Q. And if a producer keeps information confidential, obviously, as you have just stated, you would not know what that information would show; is that correct?

A. As I have just stated, we might or might not know what the situation is. What I have tried to point out is that with the committee organization, where we get our numbers, our reserve estimates through a committee of men each of whom is daily active in the energy business, in this case particularly in the gas business, and men that are experienced in estimating reserves and experienced in knowing what are the sources of data as well as experienced in judging the data from the different sources, that we have a constant contact with all sources of data. So again looking at the overall, we don't have very many cases in which there are not enough data for any period of time to not make an estimate.

Q. Well, getting back to that expendable well we were talking about a moment ago, if it were shut in without a report of any production, and if the information were kept

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confidential, what sources of information would you have available to you to find out whether or not there are reserves there?

A. Well, as I mentioned before, perhaps somebody will come along and drill another well and we'll get the data on that well.

Q. Until the well is drilled you don't have any data; is that right?

A. As I say, most of these cases where somebody wants to withhold data, they do not slow us down for more than a year. We like to put a reserve in one year's report, and we put it in the next year's report. And it is because of the case I am talking about. Somebody makes a discovery—you have looked at enough of these Louisiana offshore maps I am sure to know that these fields don't fall within any one block and somebody else will come along and drill because the first well has been drilled. And it is unusual to find a situation in which all of the data would be withheld from us.

* * * *

[4,579]

Having said all that, I must characterize the subject that is before us as the expendable well red herring.

Now, let's take the AAPG quotations. What the problem with these people is on expendable wells is that the operator

[4,580]

doesn't declare them either as a dry hole or as a producer. What the committee wants to know is whether or not this is a dry hole. The operator says well, maybe it is and maybe it isn't.

MR. COOPER: Excuse me. When you referred to the committee there you meant the AAPG Committee?

THE WITNESS: The AAPG, not the AGA Committee. Now what the AAPG Committee is after is to calculate a success ratio, and they have all the wildcat wells, all the exploratory wells in the denominator. And remember, we are talking about ten thousand wells a year here that we are keeping up with—we, both the AAPG Committee and the AGA Committee on natural gas reserves.

His question is how many wells does he put in the numerator. So his problem is that each exploratory well has to be put in one pigeon hole or the other; that is, success or dry. And on the expendable well, his problem arises from the fact that the opeartor is saying I cannot classify this well at this time, I will classify it later on, but I am saving this well so that I might possibly reenter it. Maybe I will and maybe I won't, but I might possibly reenter it. So I won't put it in either pigeon hole. So AAPG has a problem. The Committee on Natural Gas Reserves doesn't have this problem. As I have said before, it doesn't make any difference to this committee what you call the well. We take into account every

single well that is drilled. None of them are drilled in secret.

And if I may add one other thing which I think will be helpful, I do think these AAPG quotations are helpful in the sense that they bring out again the point that there is nothing secret and there is nothing nefarious about the drilling of expendable wells. This is a procedure that has been devised in order to minimize the cost of producing gas for the American public.

Q. I want the record to be clear, Mr. Jacobs, we have not suggested there is anything nefarious about the practice of drilling expendable exploratory wells.

A. I am sure that was the case.

Q. But let me button this down, if I can.

If a well is drilled which the AAPG looks at as expendable and they dont' know whether it is a producing well or a shut in dry hole, and the information is kept confidential, the AGA Reserves Committee doesn't know whether it is producing or a dry hole and consequently the AGA Reserves Committee can't put that into proved reserves unless there is an offsetting well to show that it has become proved. Is that correct?

A. But not because of the fact that it is called an expendable well and AAPG can't decide whether to put it in the numerator of their success ratio or not.

[4,582]

Again, the problem that the Committee on Natural Gas Reserves has is the problem of confidential data. And again, I must characterize all of this discussion about expendable well as an expendable well red herring.

Q. Well, I don't think you will find either Mr. Bass or the AGD or any other party to this proceeding relying upon the fact of the expendable well. We are trying to find out as you are, exactly what is in South Louisiana and what will be available. But, again, the AGA Reserves Committee would not have this in proved reserves; is that correct?

A. Would not have what in proved reserves?

Q. If the producer held the information confidential and the well was shut in and no one knew whether it was a producing well or a dry hole except the producer,

the AGA Reserves Committee would not have that in proved reserves. Is that what you have said?

A. Again, I think for the third time this morning, if a well were drilled and the data on that well were held confidential, that is, withheld from the Committee on Natural Gas Reserves, and if the committee through other sources could not obtain the necessary and minimum data to make a reserve estimate, then there would not be an estimate for that well in that year's report.

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[4,585]

A. Well, Bill, as you very well know, I run this committee, and my reputation is on the line on these numbers.

As I think any prudent administrator would do, I run constant and what I consider adequate checks on whether or not these hundred-odd people that are working for me in this enterprise are doing their job according to the rules that we have set out for them. So although I do not actually construct these estimates myself—and of course it would be impossible for any one man to do this. Remember, each year this committee looks at every gas-producing well in the United States plus the ten thousand new wells that are drilled at present-day levels. And there is no single person that could ever digest all this information. But as I say, I run the checks that I think a prudent administrator would run. So I have some knowledge and I think adequate knowledge of what is being done in these committees.

Now, as I pointed out in my written testimony, one of the problems, one of the questions that anyone, any fair-minded person would face in setting up an operation such as this is this question of accessibility to data. And

we think that we have devised a method by which we have excellent accessibility to data.

There are cases, particularly a situation where there are open leasehold properties across the line, where data has such a high value that it is not only not released to people

[4,586]

outside the business entity that owns that data, but often it is restricted to one or two people within that business entity itself. So it is obvious from the beginning that there could possibly be some data that wouldn't be available to us. So then the question gets to be, well, what is the order of magnitude of what you don't have?

Fortunately, this committee has operated now for a long, long time, has had a lot of experience. It has followed the drilling in Offshore Louisiana since the beginning.

Now, the reason that I say that the withholding has had an insignificant effect upon the figures that the committee produces is twofold: One, the cases where data have been withheld just in actual numbers are small. And as I mentioned earlier, the second factor is that the length of time over which these data were withheld is quite short. We have few instances in which we have been delayed more than a year because of withheld data. I don't think we have any instances where we have been delayed say more than three years. But that is the basis for my opinion that the withheld data is insignificant when we turn and look at the overall job that the committee is doing.

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[4,589]

Q. Mr. Jacobs, in the situation you have posed, the drainage sale approach, would the adjoining tracts which

are going to be put up for sale—would the reserves underlying those adjoining tracts be categorized as proved or probable or potential under the AGA definitions?

A. Now, the AGA definition is of proved reserves. We don't have any other definition.

Q. AGA Potential Gas Committee. I am sorry.

A. And you have already worn out my poor memory about those definitions for the Potential Gas Reserves Committee. But let's talk about proved reserves because I think your question is pertinent there.

Your question goes to the size area, the amount of acreage that the committee would consider proved by one well. I believe this is the nut of your question. This is a variable. We, after a great deal of discussion, have left the amount of acreage that one well will prove up to the individual committees. In other words, it depends upon the data that are available.

[4,590]

Data could be convincing to show proved reserves across a lease line on a lease that wasn't drilled. In another case, data would not be that convincing.

Q. In this case, then, the proved reserves could include both the drilled and the undrilled portions of a given field; is that right?

A. It is possible that could be so.

Q. Mr. Jacobs, turning to the subcommittee again, in Southern Louisiana you indicated there were, subject to check, eleven individuals doing the studies for the AGA Committee. How many fields do they have to review, or did they review in this past study in the offshore area; do you know?

A. I don't know, but again I would be glad to see if my colleague has that number with him and put it in the record here.

Q. I wonder if we could obtain a list of the fields that were actually included.

A. This is not possible. That is confidential.

Q. Would you check with your colleague to find out how many fields were included?

A. Would you like me to do that and submit this later?

Q. If you would, Mr. Jacobs. Perhaps after the mid-morning recess.

Again this is the offshore area I am directing myself to.

Now, the subcommittee members again would have checked

[4,591]

the particular fields, and you have indicated that in most of them they have obtained the information from the producers involved, but that some of them may likely have had confidential information withheld from them. Is that correct?

A. Not some. A very few might have had confidential.

Q. Do you know how many?

A. It is a small number. Very small number.

Q. Have you been told how many?

A. In the checking I have done, yes, I have an opinion of how many.

Q. Excuse me. I didn't hear the last part of the response.

A. I say in the checking that I have done as I have described, yes, I have an opinion of how many. As I say, it is very few.

Q. I gather that the number would be kept confidential.

A. This is correct. As I pointed out, the confidentiality is necessary to have access to data.

Q. At this time, Mr. Jacobs, I am not arguing with

the fact of confidentiality. I am just trying to find out how far it goes.

How much time does each of the subcommittee members put into making the study for AGA?

A. As proportion of his total time, I really don't know. In my own case I would suppose it is in the order of magnitude

[4,592]

of, oh, ten to twenty percent of my time.

On the individual committee members, I do know this: I get these things back when we have our review meetings, are getting ready for our review meetings, not only the expressions from the men themselves as to how many extra hours that they are putting in to get ready for these meetings but also get this out of the wives, which I thought is a truer measure, perhaps, of just how much time they are spending than their own declarations.

Q. As to the subcommittee members themselves, those who are making the studies, who work for individual producers or pipeline companies or distributors, about how much does the average one of the eleven members, which again you have accepted subject to check, put into the studies for AGA?

A. I say I really don't know.

Q. Now, when any individual subcommittee member has finished his analysis for a field or group of fields, does he discuss this with the other subcommittee members prior to bringing his report to the committee?

A. He discusses it with the other subcommittee members at the subcommittee meeting. This is the whole purpose of the subcommittee meetings, is to review the estimates hat have been made by the individual members from the standpoint of how he went about it, how much data he had, the reasonability of what he has come up with.

[4,593]

Q. I think you indicated in your testimony that you have two such meetings a year; is that correct?

A. This is of the main committee.

Q. That is the main committee.

A. The subcommittee will hold as many meetings as it thinks is necessary to get its job done, just as on this question of how many hours one of these committee members put in and I said I don't know. When you consider, on the other hand, the total output of the committee, that is, that each year a review is made of the producing history of every gas field in this country plus a review of, what is it, ten thousand new wells that are drilled, you can see that a great many hours are put in in this effort.

Q. Yes, I appreciate that. I am just trying to get some picture of what the individual subcommittee member would actually be doing as far as time goes.

Do you know for the 1969 report how many meetings were held by the South Louisiana subcommittee?

A. I do not.

Q. Once the subcommittee reaches a conclusion as to the estimates of reserves, again for purposes of reference, in South Louisiana, a report is made to the overall committee; is that correct?

A. That is correct.

Q. Is this report in writing prior to your committee

[4,594]

meeting?

A. The individual subcommittee chairmen report to me in writing prior to the date at which the entire committee prior to that time, the date of meeting?

A. The reports that I get are then assembled—this is one of my responsibilities—into an overall report. These overall reports are distributed to the committee members so that they have time to study them and be ready to raise whatever questions they want to raise at the meeting of the full committee.

Q. Now, as to the 1969 report again for an example, how much time prior to the meeting did the committee member have to review this? When did you send them out and when was the meeting?

A. I don't remember exactly. It would be in the order of magnitude of two to three weeks.

Q. Two to three weeks?

A. Something like that.

Q. And in that two to three weeks' time he would have to review the overall picture for the United States; is that correct?

A. He would have that much time to look at the other data and note whatever points he wanted to bring up with the actual committee.

[4,595]

Q. And after this two or three-week period you would have your full committee meeting, and you did have prior to the conclusion of the 1969 report; is that correct?

A. That is correct.

Q. Now, at the meeting you held for the 1969 report, could you tell me how long you actually met on the subject? One day, two days, a week?

A. Well, we schedule three days. Just how many hours we were in actual session, I don't really have a count of that; but the committee was together in this final review meeting for three days.

[4,595]

Testimony of John C. Jacobs

Q. Were any changes made by the overall committee in the subcommittee's report for South Louisiana?

A. I don't recollect whether there were any or not.

Q. Would that be confidential information?

A. I would consider that confidential.

Q. Mr. Jacobs, I have asked for a list of the subcommittee members in South Louisiana as to their employment. I wonder if you could indicate which of those members actually did the study for the offshore South Louisiana Area and which did it for the onshore area.

A. That is confidential.

MR. HARKAWAY: Your Honor, may we take the midmorning recess at this time? I have further questioning.

PRESIDING EXAMINER: You have further questioning?

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[4,600]

that field is abandoned. In other words, the assumption is that some of the gas that is present in the reservoir will not be produced.

Q. Now, if we were to make a calculation of the original gas-in-place, that gas remaining in the field and not recoverable would be part of the original gas-in-place category; is that correct?

A. It would depend upon what type of original gas-in-place one were estimating.

Now, if by original gas-in-place one means to signify the total amount of gas that is going to be produced from the field, then there is no reduction. If by original gas-in-place one means all the gas that is in place in the reservoir, then I say the abandonment pressure signifies an assumption that part of that gas will be left in the reservoir at abandonment.

Q. Now, the data on the pressure decline curve that

is above the abandonment pressure would all be considered recoverable reserves by the AGA; is that correct?

A. That is correct.

Q. And the gas that is below the abandonment pressure that is used would not be considered as proved or anything else by the AGA; is that correct?

A. It would not be considered as proved gas within the terms of the AGA definitions.

Q. Proved recoverable reserves?

[4,601]

A. Right.

Q. In making the study, does the subcommitteeman determine what the abandonment pressure will be?

A. This is determined by the subcommitteeman subject, as I have pointed out here, to review by the committee and ultimately—and if a specific case were of interest, subject to final review by the committee.

Q. You say it is determined by the subcommitteeman. Is it in fact determined by him or is it determined by the producer in the field?

A. Well, in making the estimate it is determined by the subcommitteeman. He makes an estimate as to what the abandonment pressure in this particular reservoir will be. He takes into account some physical factors, he takes into account some economic factors.

Q. How does he determine whether it is economic at a given level?

A. Under our definitions, he makes this determination on the basis of today's economic situation, because we don't try to estimate what the economic situation will be say twenty years from now in picking an abandonment pressure for a reservoir with a twenty-year life. So as I say, he makes his estimation of abandonment

pressures on today's situation as they are known in the area that he is working in.

Q. Would you mind telling me what you mean by today's

[4,602]

economic situation in the context about which we are speaking.

A. Well, one of the factors would be the price of gas. As I have mentioned, abandonment pressures are controlled by physical factors. This basically goes back to what sort of a producing mechanism the reservoir will be subjected to. Without going into any great detail, there are generally three types of mechanics that go on in these sub-surface strata to produce gas from the reservoir.

If we take a case in which the gas produces itself, in other words, we have the classical balloon situation that there is nothing to bring the gas out of the reservoir except the pressure that existed there initially, then the price of gas would be most pertinent compared to the other producing mechanisms in setting an abandonment pressure.

As I say, as a practical matter we have taken today's situation, today's gas prices, today's cost of compression and so forth, in making our own estimates of abandonment pressures.

I might point out—again I would hope that it would be helpful—that abandonment pressures are not important in gas reserve estimates in the sense they are in oil reserve estimates. We—technologists in America are quite proud of the progress that may be made in increasing oil recoveries because you find oil fields in which the recovery is going to be twenty-five percent; on the other hand, in gas fields we have recoveries in

[4,603]

the order of magnitude of eighty-five percent. So there isn't as much effect, if you will, order of magnitude effect upon gas reserve estimates from this abandonment assumption as there is in some of the other activities that reservoir engineers indulge in such as estimating oil reserves.

Q. Do you know, Mr. Jacobs, whether the eighty-five percent recovery factor was used in all reservoirs in the study?

A. I do not know. As a matter of fact, the abandonment pressure to be used is set in each case by the man that is making the—by the subcommitteeman who is making the study. In other words, we don't dictate any across-the-board abandonment pressure. The conditions are just too varied for that to be a sensible approach. The more sensible approach, as I say, is let the man have access to the data and know the producing conditions of that well and that field to make an estimate of what the abandonment pressure will be.

Q. But even in the South Louisiana Area, no specific abandonment pressure was set for all offshore wells or all onshore wells generally?

A. For the reason that we have different types of producing mechanisms in South Louisiana, and the engineers that are making estimates take that into account.

Q. Now, in determining what the abandonment pressure would be for the 1969 study was any direction given to keep it

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[4,605]

Q. Was it the South Louisiana Area?

A. I would say that is confidential.

But perhaps again, for purposes of illustration, the reason we don't set rules, in Pennsylvania where gas fields are produced on a vacuum, these are old fields. The wellhead value of gas has been in the order of magnitude of 27½ cents. Compression—a lot of compression can be justified and is installed. I mean an engineer is not just guessing it is going to be installed. He can see in certain fields it is installed.

Here one might assume zero pounds of animate pressure. In other words, all the gas is going to come out of that reservoir. On the other hand, you can get into situations with very deep wells in which you have a water-drive mechanism in which the abandonment pressure might be assumed as high as a thousand pounds because this is offshore, the wellhead value is less than, what, nineteen, an order of magnitude of nineteen cents. Compression is very expensive, and the engineer might very reasonably make the assumption would be put in.

Q. The engineer then with his knowledge of the field makes assumptions as to whether compression is necessary, as to whether water-drive would produce, and assumptions as to the price to be received for the gas; is that right?

A. Well, he would make assumptions. I would think that the ones that you have mentioned wouldn't be subject to much variation. The price of gas is pretty well known. The

[4,606]

producing mechanisms can be pretty well determined before production starts. And certainly after production commences, when you begin to get your pressure-production history, you begin to have a very exact history of the method. And remember, most of these reserves that we are fooling with—excuse me. Let's scratch "fooling."

Most of these reserves that we are estimating have had a number of years on the line. Remember it is just a little bit of new gas we are adding in each year to this great bank of gas that we are working with. So the price of compressors is well-known, the operating cost of compressors is well-known. Certainly these are estimates. No one could ever maintain that they are not subject to revision as further facts develop. But the particular type of estimate that you are talking about in a given producing area, I would say that this is one of the easy things that we do, a thing that there is not much doubt about.

Q. In the 1968 and 1969 reserve studies were the subcommittees instructed to use the area rates that the Commission had determined in Opinion 546 for their economic purposes?

A. No such instructions were given. We rather have used in the committee all of the gas prices that we know of in making these estimates, whether they are promulgated by the Federal Power Commission or whether they are in nonjurisdictional deals.

Q. Again in the offshore area, which would be regulated

by the Federal Power Commission, do you know whether the subcommittee members making their studies and using economic determinants used prices which the Commission had specifically set for it in its opinion?

A. In the Federal offshore area, where only FPC promulgated prices apply, those would be the prices that the committee would consider in making its estimates about the installation of compressors late in the life of the field.

Q. Except I suppose in those instances where the gas were dedicated to a direct sale such as, for purpose of

reference, the Chandeleur Pipeline Case which is not controlled by the Commission?

A. I should presume that the reserves estimates behind the Chandeleur Pipeline took into account the special purposes of its disposition. Although as we develop these questions I think we begin to ride back on another facet of the committees work and the way we have set it up to operate, again we think we have made the best of several choices, and that is, we estimate the amount of gas that is in the reservoir that we consider prudent. Now, we do not keep records that have to do with how the gas is disposed of. We don't say that this particular gas goes to this particular pipeline, therefore in this case such and such an estimate of installation of compression will be made, and because the gas next door goes to another pipeline that another abandonment pressure would be

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assumed, because the calculation of abandonment pressures is not that exact.

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A. It is a difficult question to answer. Certainly generally in making engineering and economic justifications for expenditures there are advantages in size. The larger the size the reservoir you are working in, generally attracts the larger expenditures. But, on the other hand, most of the factors that govern investment in compression equipment are a per cubic foot function. They correlate on a per cubic foot basis rather than on a total volume basis. So I say again it would be difficult to give any meaningful general answer to your question. But my

general experience has been that the important factors tie into the per cubic foot rather than to the total volume.

Q. In making the economic analysis, then, the subcommittee man would determine the cost per Mcf of investment versus the revenues per Mcf that could be returned in determining whether it is economic. Is that about what it amounts to?

A. That is one of the things that we look at.

[4,615]

Q. Are there any other economic factors other than the price and the cost of compression that might be involved in the determination by the subcommittee man?

A. Well, we are talking now about what we expect is going to happen several years in the future. And one of the factors that would be looked at would be whether or not recompletions were going to be necessary. Again, in making gas reserve estimates this is usually a fairly unimportant question because by far and large gas wells last the life of the reservoir.

In oil fields we do usually expect to make two or three recompletions over the life of the well. But generally this is unsignificant, as I say, in gas production, but it is just one of the things that a good engineer, such as our subcommittee members, will take into account.

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A. And my previous answer was responsive to that: That we examine summaries of these well status reports, again in our annual reviews of keeping up with every well and what its history has been. These well status reports are reviewed in some detail. And what my previ-

ous answer indicated is my experience is that in reviewing those reports the temporary abandonments, are, in the cases I can remember, those old wells.

Now, I also know from my experience that operators can write in that description of the well status many things, and one of our great problems is chasing down just exactly what these words that were written on the well status report meant. But regardless of the ambiguity there, the well status reports are used by the committee, and we do determine over and above anything we get out of the state agency through our other sources of information just exactly what the status of the well is. If the well turns up temporarily abandoned, why, this runs up—and we hadn't anticipated this, this runs up a —this turns on a red light and this flags it, and we check out and see whether or not there is anything unusual happened there that would affect our reserve estimates.

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A. In our committee procedures we do not take into account the availability, or possible future availability of a pipeline. There are—could be instances in which a very small reserve of gas, that is, a physical reserve of gas would not be included in our totals because it was so tiny that even if the pipeline were there it would not be exploitable in an economic sense. But the committee does not—subcommittee members do not in assigning reserves take into account the

[4,626]

distance from a pipeline.

Q. What do you mean by the term exploitable in an economic sense as you used it just now?

A. Well, to cite an example, let's suppose that a well were drilled to a depth of, let's say, 20,000 feet and that the log that was taken on this well indicated that there was one foot of gas sand and that in the hope that there might be more the sand were actually tested by the producer and that all of these data were available to us. Under most of the circumstances that I have encountered in reality, although there is physically a tiny bit of gas there which we know exists, we would not assign a reservoir for the reason that we would not expect that that gas would ever be exploited commercially. It would take quite a—these would be quite tiny reserves.

Q. Can you quantify for me what you are talking about when you say small or tiny reserves? You have used those terms several times in your recent answer.

A. Well, right now I am talking on a per-well basis. It is hard to generalize. It would depend upon the location of the well, but I would suppose one might talk about one billion cubic feet or less.

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[4,631]

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BY MR. HARKAWAY:

Q. Has the AGA made any study, or any use of the information reported by these producers in this case to see if the drilled and undrilled reserves associated with these shut-in gas completions were included in the 1969 AGA reserves report?

A. My answer goes to the AGA Committee on Natural Gas Reserves rather than the association as a whole. And the answer is no, because it is not necessary.

We are aware of the reports that the producers have used in preparing their data for the Commission. And these reports are used by our committee.

I don't mean to brag, but we think that the committee's list of wells, the sources of data that we have as to existing wells and new wells is the best there is in this country, and we think it is complete.

Now, we haven't taken what has been submitted in this proceeding as such and gone back well by well to see did we take into account that well and that well and that well because we know that we have on the one hand in our studies all existing wells and we know that each year we go to all the sources of data

that there are to bring into our records all the new wells that have been drilled.

Q. Again you are qualifying this, I presume, by the fact that some information might have been kept confidential about which you know nothing, and we have talked about that earlier today. Is that correct?

A. As I have testified and will testify again, there are some new wells that are drilled, a few, which data is withheld because of its proprietary value.

My study of this situation has resulted in my opinion that I would like to express again: That the withheld data did not significantly affect the results that were published by the AGA.

Q. What study did you make, Mr. Jacobs? The study you just referred to?

A. As to the data that——

Q. That is right.

A. ——are unavailable? Well, I think as I mentioned this morning, I have done the checking and asked the

questions that I think fit the standard of a prudent administrator to——

Q. Well, would you tell me what you did?

A. ——to find out exactly what the order of magnitude of this problem is and how much we have been exposed to it in our committee work.

Q. I have no doubt that you have done what a supervisor should do in this area. But would you tell me just what you did?

[4,633]

A. Well, what I have done is to discuss this question in some depth with the men under me that prepare reserve figures in areas where withheld data can be a problem.

Q. Is that the subcommittee members or the committee members that you discussed this with?

A. It would be both.

Q. With both. And did the subcommittee members in the South Louisiana area tell you how many wells were kept confidential?

A. I think I must necessarily take the position that the details of my discussions with the committee members are confidential.

Q. When you conclude that they are not significant, this is based upon the discussions that are for purposes here confidential discussions and which I would not want to breach as confidential discussions. Is that what you are telling us?

A. Well, I explained this morning my opinion, which you have brought out with your questions is based upon rather lengthy and detailed discussions with the committee members and subcommittee members involved—the basis of my opinion rests on two aspects of the problem: One is that the withheld data are few in number,

and the other is that they are withheld for a very short time.

I think it is important to keep in mind the concept of reserves that the committee data represent. This is not a

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Q. Yes. Mr. Jacobs, the gas reserves report lists reserves by states, and in certain instances parts of the states. Is that correct? At page 120 of the 1970—Volume 24 of May 1970, the reserves as of December 31, 1969, you show——

A. Would you repeat the page number, please?

Q. 120. Is that correct?

A. The table on page 120 of the May 1970 report lists proved recoverable reserves in the United States by states and in some instances the states are subdivided.

Q. The report does not set forth the gas reserves by geological area such as the Hugoton-Anadarko or the South Louisiana or such. It is by states only; is that correct?

A. I believe that the areas you mentioned are not geological areas but are Federal Power Commission pricing areas.

[4,637]

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Q. What is the type of information that would be provided to the subcommittee member in that case?

A. The type of information would include such things as a log or logs on the well, core data that were obtained in drilling the well, and the tests that were run on the well to prove that it was a productive well.

Q. Now, would this information be obtainable not only for purposes of making estimates of extensions and revisions but also for new discoveries? New field wildcats, even?

A. In most instances—in nearly all instances, yes.

Q. Now, in view of your answer, Mr. Jacobs, I want to ask you now to explain, if you would, the nature of any rules or concepts of confidentiality that apply between producers. The confidentiality you have described is access of the public to data that may be available only to the AGA or to the committee

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or to the subcommittee. But from the testimony you have just given, it would indicate to me that the producers are in a position to have access to the other producers' data so that there is a general spreading, general dissemination of knowledge—perhaps not published—on behalf of the various producers who work for various companies among themselves of the operations and the reserve potentials, the reserves inventory, the current status of wells and so forth, of other producers.

And I wondered if the concept of confidentiality comes in there as between one producer and another.

A. I am not exactly certain what you mean about the concept of confidentiality between producers. Now, let's——

Q. Let me make my question more clear.

A. Please do.

Q. If the subcommittee member that is employed by Humble Oil can get the reserves information necessary to evaluate Texaco's reservoirs, why can't the public get it?

A. Well, for the reason that in submitting these data to a subcommittee member, the company owning the data, whoever it may be, knows that those data will be considered with the confidentiality that is characterized by committee procedures and publications. Whereas if the data were made available to the public, there would be no such limitation of its use.

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Q. Now, in making the estimate of the reserves for a given well or field or reservoir, as the case may be, what is it that the subcommittee member prepares? What does it look like? Is

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it a piece of paper, is it done on a form, does it involve a formula—standard formula for reservoir calculation? Or, in other words, what I am trying to get at, Mr. Jacobs, is what is circulated at the subcommittee meetings.

A. Well, I think I can best characterize it as a summary showing the results—that is, the estimated reserves and the primary factors that he has used—the subcommittee man has used in calculating this reserve.

I hope my analogy is not a bad one, because it has been several years since I have been involved in this, but as I remember, the FPC staff used to have some summary forms that were used on per-field reserves. And what I am trying to get at, I think most any reservoir engineer would come to a fairly simplified summary form, as I say, which set out the results and the pertinent factors.

Q. Does the committee see this data?

A. If it wishes. In other words, if the perusal of the summary form would raise questions, then the subcommittee member would lay out the data; and again, these are all experienced men, he would let them take their own look at it and see whether or not the numbers he has used are in their opinion proper ones.

[4,644]

* * * *

Q. Now, I want to touch on another area. I notice from your testimony that you are one of the founders of the Potential Gas Committee. I was wondering having that experience and now as the Chairman of the Committee on Natural Gas Reserves, whether or not you could say on the basis of your knowledge that where the AGA reporting of proved reserves leaves off, that at that very point is where the Potential Gas Committee picks up. In other words, I want to be sure that there is no overlap or no gap in the reporting of the reserves in one source as opposed to another.

A. I would like to give two answers to that question, if I may.

If one is thinking in terms of the approximation that is involved in the potential gas reserve figures—and these figures are quite rough or quite approximate as compared to the sort of studies that the Proved Reserves Committee makes.

[4,645]

If one is looking at the total United States situation from the standpoint of Potential Gas Reserves Committee, I would think that the answer to your question would be that, yes, one can take the three categories that were

mentioned in the testimony this morning and add to it the proved reserves and have a complete picture of the United States, proved and potential, in the terms of the possible magnitude of error in the potential figures.

Now, on the other hand, if one turns around and looks through the other end of this shall we say horn of cornucopia, from the standpoint of the man who calculates the proved gas reserves, then we get into all sorts of discussions as to a every exact fit between proved and what shows up in the Potential Committee's figures as probable. And there there could be a lot of discussion about how close they would fit. But I say for a look at the overall United States, proved plus potential, I would think the figures could be added together and the total used as a reasonable figure.

Q. Now, I would like to ask your opinion on something now, Mr. Jacobs, if you would be willing to give it. I wonder if you think it would be helpful if the Potential Gas Committee reported their reserves on the same geographical basis as does the AGA report proved reserves.

A. You have asked for one man's opinion. I think not, for the reason that I believe that such a breakdown of potential

figures would give them a cast of exactness that they by their very nature do not have. It seems to me this difference in reporting areas, at least when we get to pondering that, that is, why don't these guys put out figures that we can add up and put into equal columns and run a Comptometer on them and get the same numbers both ways, well, one of the reasons why they don't and that they shouldn't is they are two different kinds of numbers, the proved reserve number being a very exact number

and the potential reserve number being a very approximate number.

Q. Would your answer change if I asked you only to limit your answer to the probable reserves category as opposed to the other categories?

A. It would not change.

Q. Now, you also testified that if prices—I think it is the thrust of your testimony. I will characterize it and if it is not accurate you can correct me. That if prices were increased in, for example, the Southern Louisiana Area, that might well justify the installation of additional compression and that in turn would have the effect of actually increasing the—in essence creating additional proved reserves.

A. This is the thrust of my testimony.

Q. Yes. And I would like to know whether you could calculate approximately how much—how many Mcf of reserves

[4,647]

would be added by, for example, a one-cent increase in the price for the volumes flowing in Southern Louisiana.

A. Again, if I may, two answers.

In my opinion, an increase in the order of magnitude of one cent would not increase the reserves; that is, it wouldn't change an engineer's estimate of what the abandonment pressure may be.

Q. Right.

A. I would thing it would take increases—well, I will use an example, ten cents in order to have an appreciable effect. And this is part of what I was trying to say, although I am not sure I said it clearly enough in answering the questions earlier. And that is, I recollect the price differentials in South Louisiana that I have been questioned about may be in the order of magnitude

of one and a half or two cents. Well, again I wouldn't expect that that would have a noticeable effect upon proved reserves.

The other side of the answer to your question. Let's suppose that we have forgotten about the penny case and your question is well, what about five cents. And I say, well, it ought to be ten. You say, well, I want to know about five. It would require a detailed study on a reservoir-by-reservoir basis to answer the question with very lengthy time-consuming study. I don't think generalization would be meaningful in trying to differentiate for a few cents. As I say, I think

[4,648]

if you get up to the ten-cent category you could expect that there would be some effect through the lowering of expected abandonment pressures.

Q. All right. Taking the ten-cent example, it increases ten cents in Southern Louisiana. I take it then that the people on your committee in your subcommittees by virtue of the information to which they have access and on the basis of the parameters that you have established for making these calculations, that it would be possible then to come up with an area-wide Southern Louisiana estimate of the amount of volumes that would be saved or new reserves that would be created, however, you want to look at it, by an assumed increase of ten cents in the price. It would be reasonably comprehensive and reasonably detailed and reasonably accurate?

A. It would be a prodigious undertaking to expect to be forthcoming from a voluntary committee.

Q. Mr. Jacobs, I would like to ask you one last question that I think is I might say just by way of preamble that as far as we are concerned goes to the heart

of the matter. Turning to the testimony that you have given here. Are you generally familiar with the way that the AGA reserves are used in the costing of non-associated gas? Are you generally familiar with what the Commission has done in the past?

A. I am not generally familiar with these detailed proceedings.

[4,650]

* * * *

Q. Every Mcf ever produced from a field is at one time or another during the course of the life of that field accounted for as an extension, revision, new field or new reservoir? I want to reaffirm that that is your testimony. Based on annual checks of the reservoir by reservoir?

A. If we add to your question production, in other words, every Mcf that is produced we had appear in the AGA figures either as production, an extension, revision or new discovery, the answer is yes.

Q. I have one last question I would like to ask you, Mr. Jacobs, and that is I believe in your testimony you said that the membership of the subcommittee is limited to people in the industry on a theory that they were the only people who could be productive in the work of the subcommittees. Is that your view of a hard and fast rule that will in all cases be applied, or is it possible that the committee might at some point consider allowing membership at the subcommittee level on an observer status?

A. In my opinion it would be a very great mistake to introduce observers in the procedures of this committee.

[4,651]

Testimony of John C. Jacobs

[4,651]

I differentiate the way we set up the Potential Gas Committee. There is no question of confidentiality there. Basically two kinds of numbers are sought after: The one is volume of undrilled sediments and the other is the per cubic mile recovery factor. These are so approximate that there is no confidentiality involved. In the case of the work this committee does, I say confidentiality is a key to ready access to data. We don't have anything that we are covering up. We don't know what the function or purpose of an observer would be. We are perfectly happy and welcome opportunities to take part in hearings such as this, to be cross-examined on our procedures. I mentioned this morning we are in contact with organizations that are outstanding in this field, such as NERA, asking for their suggestions as to what ought to be done or not done. We don't see anything to be gained by observers, and we can see that a great deal might be lost. We are not interested in having committee meetings with observers sitting around so that nobody says anything. We have to have meetings in which these people have a great deal of give and take, and we think the committee would lose a great deal if this were cut off.

Now, in regard to observers, my own position as chairman with any organization, and particularly those that are parts of our Federal Government, is that we will sit down with representatives of that organization and talk at whatever

[4,652]

length and at whatever times those particular people want us to talk and answer their questions as best we can answer them. We think that with this approach we

can obviate any need for observers and at the same time we don't have the loss of open discussion that observers would necessarily bring with them.

* * * *

[4,688]

PROCEEDINGS

PRESIDING EXAMINER: All right, gentlemen, let's proceed.

JOHN C. JACOBS, JR.

the witness on the stand at time of recess, resumed the witness stand, and, upon examination testified further as follows:

PRESIDING EXAMINER: Mr. Wheatley?

CROSS-EXAMINATION (resumed)

BY MR. WHEATLEY:

Q. Mr. Jacobs, referring you to transcript 1425 where you set forth the definition as used by the committee of proved reserves.

Now, under the definition I would like to ask you questions relating to that part of the definition that refers to "under existing economic and operating conditions."

Where are the criteria set forth to guide the subcommittee members under this part of the definition?

A. Well, the details other than the definition which is set forth here are not in writing. This is the type of definition that is ordinarily given to a professional engineer in making an estimate of reserves. And it is as complete as is necessary to guide an experienced man.

Q. So that there is nowhere any specific written criteria as to what constitutes existing economic and operating conditions?

[4,689]

A. Well, these criteria are a matter to be determined by the engineer who is making the estimate. These are experienced men. As I say, this is the normal way, normal type of instruction one gives an experienced engineer in asking him to make a reserve estimate.

Q. Well, it presumes, does it not, that the engineer knows the existing economic conditions?

A. The engineers on the committee and subcommittees, as we pointed out, have been carefully chosen because of their daily activities in the gas business and particularly in the reserve-estimating side of the gas business.

Q. Well, at transcript 1429, in answer to the question appearing in the middle of the page you state that a change in the price level in some cases could cause a change in the committee's estimates of reserves recoverable under existing economic and operating conditions. Is that not true?

A. Do you refer to the question that is characterized in my testimony as the Gooch Question No. 16?

Q. Yes.

A. Which reads "Would a change in the price level of natural gas cause a change in the committee's estimate of reserves recoverable 'under existing economic and operating conditions'? What is your answer?" Answer: "In some cases, yes. For example, an increase in the price level of natural gas might justify additional compression which, in turn, might increase the recovery factor of the fields to which

[4,690]

the compression was applied."

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[4,698]

* * * *

I said generally in my opinion a price change in the order of magnitude of say a couple of cents would have a negligible effect upon the committee's estimates. On the other hand, I should think that a price change, all other conditions being equal, in the order of magnitude of ten cents might have an effect upon the committee's estimates.

* * * *

[4,711]

* * * *

A. I testified at some length yesterday to the effect that there are a few wells drilled in which the proprietary interest in the data is so great that these data are not available to the committee for a short period of time. I say again I characterize this as a few instances, in my opinion, few enough that the withheld data does not have a significant effect upon the results published by the Committee on Natural Gas Reserves.

* * * *

[4,712]

PRESIDING EXAMINER: Well, the question is that if they don't report the wells to you or what is in them, how do you know how many there are?

THE WITNESS: Well, the point is, your Honor, that we do know how many wells there are, and we know how many that we did not get information on. Consequently, I know that the ones that we did not get information on are a few.

[4,712]

Testimony of John C. Jacobs

BY MR. WHEATLEY:

Q. How many are there?

A. This is a matter of confidentiality within the committee.

* * * *

[4,713]

THE WITNESS: I would consider that is a confidential matter within the limitations that our committee operates.

* * * *

THE WITNESS: Your Honor, to the best of my recollection at this time, the number is less than ten.

* * * *

[4,730]

* * * *

BY MR. HARKAWAY:

Q. Mr. Jacobs, you answered in response to a question asked by counsel that there were approximately ten unreported wells. Were you referring to South Louisiana in your response?

A. I testified——

PRESIDING EXAMINER: He didn't say ten. He said there were less than ten.

THE WITNESS: I think I testified, yes, your Honor, that

[4,731]

the number was less than ten. My answer does apply to the entire United States ex the Alaska North Slope, which, as I testified yesterday, is a special case in itself.

* * * *

[4,734]

MR. HARKAWAY: Though I do have one question on this area, if I might, and if I am not treading onto confidentiality.

BY MR. HARKAWAY:

Q. Mr. Jacobs, do you have any idea what kind of wells these were? Were they discovery wells, were they development wells, or in giving an answer would that be giving a confidential response?

A. That would be a breach of confidentiality.

Q. One further question. In response to other questions of Counsel Wheatley, you indicated that the price impact—and I am paraphrasing your response this morning—the price impact was on the abandonment pressure, and we went through this to some great degree yesterday. Would the change in price have some effect on whether or not a producer would add compression to recovering gas from an otherwise unrecoverable gas area? Is this a different impact that might be considered?

A. Well, if I understand your question, you are asking the same—about the same situation, that is, that the addition of compression and the abandonment pressure are correlative.

MR. HARKAWAY: That is what I wanted to clear up. Thank you, Mr. Jacobs.

MR. SIMONS: Mr. Examiner, before this witness leaves the stand, I would like to comment on the confidentiality shield that

[4,736]

* * * *

Q. Mr. Jacobs, I show you page 4676 of the transcript of yesterday, line three, where it says, as the

reporter has it, "The Witness: Excuse me. Proposed exhibit is correct." Do you have a change to make in that?

A. Yes. What I said was "Excuse me. Assuming the proposed exhibit is correct." The words "assuming the" were omitted by the reporter.

Q. On 4633, lines seven through twelve, Mr. Harkaway asked you a question, "And did the subcommittee members in the South Louisiana area tell you how many wells were kept confidential?"

Do you want to clarify your answer to that question?

A. I would like to to this extent: That is, that it is the data from the wells that is kept confidential and not the wells themselves. As I have testified, the committee has knowledge of all the wells that are drilled in the offshore area as well as the onshore.

* * * *

[4,740]

PRESIDING EXAMINER: All right.

DIRECT EXAMINATION

BY MR. COOPER:

Q. Mr. Jacobs, I hand you the document that has been marked for identification as Exhibit 49 and ask you whether Part II of that document, beginning on page 85 and extending through to page 265, is the report of the Committee on Natural Gas Reserves of the American Gas Association as of December 31, 1969?

A. It is.

Q. And that is the report to which you have been testifying during the past two days?

A. That is correct.

MR. COOPER: Mr. Examiner, I would like to offer Part II of Exhibit 49, being, as I have said before, pages 85 through 265, in evidence in this proceeding.

MR. SIMONS: Mr. Examiner, I would object to the receipt in evidence of the portion of the AGA report as defined by counsel.

The report lacks probative value, and it lacks probative value because the basic underlying data is not made available and cannot be seen by the public. It has been cloaked in a mantle of confidentiality from the beginning. There is simply no way, shape or manner to test the reliability of this other than to do what Mr. Jacobs has suggested, to have faith in the members

[4,741]

of the committee. But that is not a legal basis for receiving data in evidence.

Now, the objection that I am making, Mr. Examiner, I think goes to the very heart of what kind of proceedings we are going to have here before the Federal Power Commission, whether, when you announce to the public or when you tell a court that we had an evidentiary hearing and a full record and full cross-examination you are keeping faith with the concept of due process in American life, or whether you are simply engaging in a great charade where there is no meaning, there is no honesty, and there is no truth whatever in what is being done.

If this report cannot be tested other than to say that we have faith in the people who compiled it, if you can't go back to the basic data, if you remember that the people who compiled it are people who work for the industry that is requesting the increase here involved, if you remember that at the time that they prepared it they were

perfectly well aware what arguments would be made from a shortage in reserves, from a decline in reserves, and what arguments would be made from an increase in reserves, then it seems to me there is nothing that you can do other than to say that this report lacks probative value, it cannot be tested, it is not competent evidence, it is not competent for any purpose. There is no basis for accepting it under even that old, tired wheeze, "for whatever it may be worth", or under that old excuse for avoiding decision, "well,

[4,742]

the argument goes to the weight to be accorded, we will take it in and we will see about it later when we come to write a decision". Because if it is in the record, it is going to be cited as record data; and if we have record data, that record data ought to be factual, it ought to be competent. People ought not to be able to say there is something in the record when that record data does not really mean anything at all. And this data doesn't mean anything at all, and there is no way to test it to find out whether it means anything at all.

Accordingly, Mr. Examiner, I would urge with every ounce of vigor at my command that this exhibit be excluded from admission in evidence.

I would also point out that if this data is wanted in by the moving parties, they can make it competent, they can make it have probative force by making available the data which underlies it, and by making available as witnesses the people who prepared the reports and have them come with the reports that they prepared.

The question is not whether it goes in or not; the question is whether it goes in in a competent manner or not.

There is certainly no basis in American law for putting in a series of summary reports where the underlying data is hidden from public view and using that data against any party to any proceeding. When that is done, you have the merest shambles of a trial, you degrade the whole adversary and hearing process. And I don't think, Mr. Examiner, that the Federal Power Commis-

[4,743]

sion should be a party to that, and I don't think that you should permit yourself to be a party to that.

Accordingly, I object to the exhibit; I ask that it not be received in evidence for any purpose whatsoever.

MR. WHEATLEY: Your Honor, on behalf of the municipal distributors group, we wish to second Mr. Simons' objection to receipt in evidence on the very relevant grounds that he has put forth.

We believe that the cross-examination that has taken place these last two days demonstrates beyond question that there is no way in which the truth and accuracy of the figures contained in this report can be tested by any other party to this proceeding.

The confidentiality claim that is made as to all of the data presented here precludes any such ability by any party.

We believe that the very fundamental question of due process of law is involved in this matter, and we submit that it would be certainly contrary to the interests of the consumers of this country if data prepared by parties with an interest in the outcome, and a conflict of interest, I might say, in preparing any material that would be inconsistent with the positions which are expressed by their companies before this Commission,

should be adopted here by the Commission as evidence and as proof of the very facts which are being asserted.

And we strongly second Mr. Simons' objection on the various

[4,744]

grounds that he has stated in putting forth that objection.

MR. NORRIS: Your Honor, if I may, I submit that the bridge has already been crossed as to whether the figures appearing in this report will be in this record.

Exhibits 8 and 8-A contain these figures. It is not necessary for my purposes that Exhibit 49 be admitted, but I would suggest to Your Honor that rather than the bare figures that appear in Exhibit 8 and 8-A, it would be helpful to have the explanations which appear in Part II of the AGA report also in the record.

As counsel Simons points out, the weight to be given these figures has not been determined on this record. However, the data in that report gives a little fuller picture of what went into the numbers and the strictures which surrounded them.

Now, whether this is evidence of the type on which reasonable and fair minded men would rely might be indicated by the fact that the Federal Power Commission in both the Permian Basin and the Southern Louisiana decisions made use of this data. And I think that perhaps no substitute for it has been suggested. Therefore, I would ask Your Honor to admit it as helping to have a more complete record in this case.

PRESIDING EXAMINER: Didn't staff use these figures in the preparation of Exhibit 9?

MR. NORRIS: Yes, Your Honor.

MR. MATTINGLY: Yes, Your Honor.

[4,745]

PRESIDING EXAMINER: Do you have any comment?

MR. MATTINGLY: Yes, I would like to make a few brief comments.

MR. GOLDBERG: Perhaps before Mr. Mattingly—is Mr. Mattingly going to respond to the statement that has just been made?

MR. MATTINGLY: I would like to respond very briefly, yes.

MR. GOLDBERG: Because I was going to respond to the statement that has just been made.

MR. MATTINGLY: Go right ahead.

MR. GOLDBERG: And as to the Examiner's inquiry about Exhibit 9.

Exhibit 9 on its face states to anyone who reads the report that the figures that are published by the American Gas Association with respect to reserves, which are the subject of this Exhibit No. 49, were accepted at face value, and the staff was not vouching for those figures and could not vouch for those figures. The staff confessed they had no ability to confirm or analyze or verify those figures. So that Exhibit 9 cannot possibly furnish a predicate for putting Exhibit 49 into this record.

With respect to the proposition that the Commission has used AGA figures in the Permian Basin and Southern Louisiana cases—that is, the first Southern Louisiana cases, I would remind the Examiner that those represented the Commission's

[4,746]

initial efforts without having gathered any data which it could turn to in order to fix area rates.

[4,746]

Testimony of John C. Jacobs

Now, the Commission has proceeded in that fashion for too long a time now. The Commission has all the power it needs to secure data that is reliable. And that applies to this Exhibit No. 49. It has the power to get behind these data an find out if it is reliable. And the time has arrived for calling a halt to reliance on figures that cannot be verified, that cannot be vouched for. So that to refer to Permian Basin and to Southern Louisiana area proceedings as a predicate for using this information unverified at this late date simply won't wash.

PRESIDING EXAMINER: Mr. Goldberg, whether I personally agree with you or not, I think it would at this point be quite irrelevant. Your argument along those lines would be better addressed to the Commission than to me.

MR. GOLDBERG: Not at all, Mr. Examiner. You are fully empowered to decide in this case whether this should be admitted. And being fully empowered to decide that, you have the full power to decide that the time has come to call a halt to letting into the record unverified data which Mr. Simons very correctly points out will be lost sight of. And once it gets into this record you will be talking about it as probative evidence when in fact that has never been established.

PRESIDING EXAMINER: Mr. Goldberg, isn't it a fact that

[4,747]

this report is used quite extensively throughout the industry?

MR. GOLDBERG: That proves nothing. Index figures——

PRESIDING EXAMINER: I am not asking whether it proves anything. I am asking you whether or not it is not a fact.

MR. GOLDBERG: I couldn't say to you how extensively it is used, or for what purposes it is used.

Now, assuming arguendo that it is used extensively, it may be that the use of that report for the purposes used by private people may be fine. But you are talking about the use of this report as a basis for reaching determinations that affect consumers all over the country. And they are entitled to have the best possible information, and not just someone's suggestions that we have faith.

PRESIDING EXAMINER: Mr. Mattingly, you were going to make a comment?

MR. MATTINGLY: Your Honor, I do believe this is a matter that is essentially an argument that has been addressed to the Commission on a number of occasions and I think will undoubtedly be addressed by a number of parties, as has been done, in this proceeding. But at least from my point of view, from the staff's point of view, this is how we would view the situation.

Certainly these data are the only data of this nature that we know that are available. They are the only data in the world that are available to indicate the trend of reserve additions, the actual reserves, and the various other statistics

[4,748]

that are presented for the natural gas industry on a total U. S. basis. So in that respect, there is no alternative.

Now, these data have been consistently prepared. They are a continuing data series going back to 1945. I would represent that they have been accepted by Government agencies, both Federal and State. They are accepted by the industry. They are accepted by anyone—the economic, banking industry. Any industry that has to deal with these problems has in fact and does rely on these data.

These data have been used in every single area rate case before this Commission. Their use has been consistently approved, along with various other published statistical data series from a wide variety of sources including the Federal Government, the state governments, various business organizations, whose information, as stated by the Commission in its opinion, is essential to obtain information on a nation-wide basis for these nation-wide gas reserves and costs and other data that are necessary.

Now, beyond that, the use of these data for the purposes for which the Commission has used them has been uniformly approved in judicial review by the courts. Their use has been conclusively affirmed by the Supreme Court of the United States in its opinion in the Permian Basin area rate cases.

Now, in this particular proceeding, in addition to the published definitions and procedures and explanations that are

contained—the extensive explanations that are contained in the annual report, the staff has undertaken in cooperation with the witnesses sponsored by the united distribution group—we have previously by our letter sent to—a general counsel's letter sent to Mr. Jacobs, asked him pertinent, pointed and direct questions which we considered appropriate for developing the issues, for enlightening all of the parties to the extent possible as to the precise nature of who does this work, how it is done, how the figures are prepared. I think the evidence in this case for that reason is much more extensive than it has been in any of the past proceedings.

Now, it is our position, certainly, that the data are—in demonstrating that the data are entitled to sub-

stantial weight, we think the data—we would not purpose to argue that at this time because that essentially ultimately will be a matter for determination by Your Honor and by the Commission and ultimately by the courts. And being reasonable men, obviously we are going to be willing to live by the results of those decisions; however, we think that it is simply not valid, it is not appropriate, in an attempt to exclude this evidence, to simply allege, after Mr. Jacobs has come up here and testified on the basis of his appearance in this proceeding—to simply allege that the reason that they are entitled to no weight is to assume bad faith on the part of the committee or the subcommittees or Mr. Jacobs himself. I don't think that is

[4,750]

certainly any such reason for keeping them out.

And I think all of the indications, all of the factual background, all of the nature of the arguments point all in the direction, Your Honor, clearly, of admitting these data into evidence and using them as is necessary to make the determinations for which the data are appropriate in this proceeding. And I think that from every standpoint at least that I can think of, based on precedent, based on common sense, based on the objections of reasonable men, and based on even the Commission's rules, 1.26 that govern this particular decision, that you are going to have to make—as far as I would be concerned, Your Honor, and it would be the staff's position, that all of these indications point to the receipt of this evidence in this proceeding.

MR. SIMONS: Mr. Examiner, I would like to respond to Mr. Mattingly, primarily, as well as to certain questions that you raised. If this is the appropriate time to do it, I will do it.

PRESIDING EXAMINER: Go ahead.

MR. SIMONS: With respect to whether this material was received and relied on in Permian and in the first Southern Louisiana case, first of all, it was received without objection and I believe by stipulation. In this case there was no stipulation on it. The reason that there was no stipulation is because we felt that the data was being jimmied and we had seen how the data were being used against us. We no longer wanted

[4,751]

to acquiesce in that kind of a suicidal project.

Now, the second difference is that when you use industry data for a second time, you run this very severe risk that it will be altered to fit the arguments being made by the industry when they know how it is going to be used. In the first case this was a series that had been used for a long time, and it was used by the Commission. When it had been prepared it had not been prepared with the idea, and the people who prepared it hadn't known how the Commission would use it. After Permian, they did know. And look at the sharp differences that we got in the last two years just prior to this proceeding: Very marked differences from anything that happened before. this is not some sort of wild suspicion.

Now, as to Mr. Mattingly's statement, therefore, that this procedure has been approved by the Commission and approved by the courts and approved by the Supreme Court, he is just as wrong as he can be. It was never raised in those cases. No issue was ever made of it in those cases. Courts do not reach out and decide issues that are never raised. Nobody challenged the use in those cases. So to say that there is some precedent on this is just completely wrong.

You are not bound, there is no holding—Mr. Mattingly did not cite a single holding and you cannot cite a single holding that says when there is objection to this kind of non-probative data it can go in. It can go in by stipulation. We

[4,752]

do not stipulate. I hope that that point is clear.

Now, he says that it should go in because they are the only data that are available. And I must confess that I find this a pathetic response for counsel for the Government agency charged with regulating this industry.

Developing the point made by Mr. Goldberg, why has the staff not gotten other data available?

I am at a loss to understand the position being taken by the Office of General Counsel in their little dispute with the Federal Commission as to whether they have jurisdiction to get this data. The fact that they haven't gotten reliable data does not justify putting unreliable data in. The fact that they have not obtained probative evidence doesn't justify putting non-probative evidence in.

Now, Mr. Mattingly referred to the Gooch questionnaire, but the major and most important item that that questionnaire demonstrated, and which has been corroborated by Mr. Jacobs' testimony on the stand, is that every time you go to look for something, down comes the shield of confidentiality, there is no way you can find anything. In part, the questionnaire was very useful for that purpose, because it demonstrated, as had never been demonstrated before, that this report lacks probative value unless the shield of confidentiality is dropped and unless the basic underlying data are presented.

Mr. Mattingly says that the objection seemed to be based

on the assumed bad faith of committee members. That is not so. There is no assumption one way or the other. But the offer in evidence—and the burden is on the party offering—the offer in evidence is based on the conclusive assumption of good faith of committee members, and there is surely no basis for that. Parties are entitled to examine the committe members who prepared the reports, and they are entitled to see the reports.

Now, one final point. Mr. Mattingly indicated all of the factors that he thought that the receipt in evidence of this data could be based on, and he mentioned percedent, and I think I have taken care of that, and Commission rules, and so on. I think it is extremely significant, Mr. Examiner, and I perhaps end where I have started at the very beginning, that one of the factors that Mr. Mattingly did not mention when he mentioned factors that pointed to admission was the very basic one in our whole judicial concept. The concept of due process. If you can't cross-examine this data meaningfully, it can't be in. If you can't get the people who prepared it and ask them what they did and why they did it and how it differed from what they did last year and what field it related to and where they made their revision and what their basis was for it, then the whole report has no real meaning and the kind of a trial that we get at the Federal Power Commission should be reported by Franz Kofka.

MR. COOPER: Mr. Examiner, I don't know whether you desire

[4,754]

any argument from me or not.

PRESIDING EXAMINER: I think I have heard enough. And I will reserve my decision on the admission

of this exhibit until at least 2 o'clock. We will recess now until 2 o'clock.

I don't think it is necessary to hold Mr. Jacobs. We won't need him any more.

(Witness excused.)

(Whereupon, at 12:30 o'clockk p.m., the hearing was recessed to reconvene at 2:00 o'clock p.m.)

[4,755]

AFTERNOON SESSION

PRESIDING EXAMINER: All right, gentlemen, let's proceed.

Staff counsel has asked to be heard.

MR. MATTINGLY: Your Honor, I wanted to simply make an additional remark or two that I think will be in order, that Your Honor will find in order prior to Your Honor's ruling on the matter which was left prior to the noon recess.

I wanted to be sure that I stated on the record that it has been the testimony of staff witnesses in this proceeding that have been cross-examined to date that the trends in reserve additions and gas supply as reported by the AGA have been in fact confirmed in large degree by the data which is reported to the Federal Power Commission on FPC Form 15.

I also want to say this with respect to the suggestions that were made this morning by counsel for the New York Commission relating to his request that we undertake, and parties have access to AGA information that would allow them a review and analysis of all of the underlying work papers of the AGA used in preparing its report.

[4,755]

Testimony of John C. Jacobs

In our view, Mr. Examiner, this would require essentially the creation of an organization or a bureau which would be essentially similar to the AGA and it would require essentially a duplication of the effort and the work which is done by the AGA. I would suggest that the parties and the Commission and Your Honor must consider in making a decision on this matter—must

[4,756]

consider the spirit in which the request was made. Irrespective of any arguments which may have been advanced, which were advanced, we must be aware that what has been requested by the New York Commission and by certain of the other parties is a massive data collection, analysis and review procedure which they must know, and which I would state at the present time is beyond the capacity and the resources of the Commission staff at this time for us to undertake at this time. And I think that we must be careful in these proceedings to distinguish between the need for data—between the need, for example, for an ever increasing mass of detailed technical reservoir data on the one hand and any attempt by any party to vitiate the objectives or the progress of this proceeding.

Now, in that connection, Mr. Examiner, that is, the question as to whether this mass of underlying data are in fact necessary, I would like to detail for the benefit of those gentlemen here and for Your Honor and for the record some experiences that we have had in that connection.

Now, in the very first area rate proceeding in the Permian Basin evidence was presented by a member of the Committee of the Natural Gas Reserves Committee of the AGA, Mr. C. E. Turner. In response thereto the

staff requested that he provide the work papers which underlay his exhibit. Now, those work papers were comprised of approximately three steamer trunks full of all of the individual reservoir factors and individual sheets of

[4,757]

analysis that were used in the preparation of the data in the AGA report for the Permian Basin area. The material was reviewed by the staff; it was put on data tapes, and exhibits were prepared therefrom and submitted in that proceeding together with related testimony.

Now, I would not attempt at the present time to characterize that testimony, but I would think that in view of the isssue that has been made in this proceeding, it would be helpful to incorporate that material in this proceeding by reference to the official record of the Permian Basin. And I have those citations and I would propose to have that material incorporated at the present time. That is, the testimony and exhibits of Mr. Clarence E. Hamilton, Staff Witness.

MR. HOLTZINGER: I am just not clear, Mr. Examiner. Could I ask counsel a question?

PRESIDING EXAMINER: All right.

MR. HOLTZINGER: You are referring to the testimony of the Witness Hamilton in Permian. Is that National or Permian Basin testimony?

MR. MATTINGLY: Subject to—I will give you my own understanding, that it is Permian Basin data. I would stand corrected by any of the parties, but I believe it is Permian Basin.

MR. HOLTZINGER: The other question I had is there was a witness by the name of Brammer presented by the staff in AR61-2, and I was wondering if that was available updated.

MR. MATTINGLY: Well, Mr. Holtzinger, I cannot answer your question specifically. What Mr. Brammer had in the original AR61-2 proceeding is, of course, incorporated by reference by virtue of the order which instituted this proceeding. Now, I believe I stated at an earlier point in the prehearing conference that we did not propose to update that exhibit.

MR. HOLTZINGER: My question was had it been updated.

MR. MATTINGLY: No. We have nothing further to add.

PRESIDING EXAMINER: I don't know if this has any relevancy here at this point.

MR. MATTINGLY: Your Honor, I think the only point that I am trying to make, and I am not going to insist that this material be incorporated by reference, although I think it would be extremely helpful, is that we have had experience with attempting to get this massive detail and data and trying to work through these work sheets. I might state that the conclusion that was reached by the staff was that there was no substantial deviation, no substantial error in the reserves calculations as made by Mr. Turner. So I think that is another—it is simply another factor, it is another factual consideration which, as I indicated earlier this morning, all go to establish the validity of the data that is in question at the present time.

Personally I think it would be very helpful to have that material incorporated by reference here. I can provide the

citations to it.

PRESIDING EXAMINER: Well, I would rather not hear any more argument on this. I am prepared to

give my ruling on the admissibility of the exhibit.

MR. GOLDBERG: I would simply like to have the record show, Mr. Examiner, that Mr. Simons is not here, nor is Mr. Wheatley here. And I am sure they left with the expectation that there were going to be no further statements.

PRESIDING EXAMINER: Well, I think whether there were or not, if they were that anxious they might have appeared here to get the ruling.

MR. GOLDBERG: Well, I am here and I would like an opportunity to briefly—

PRESIDING EXAMINER: You are here and I am prepared to make a ruling.

MR. GOLDBERG: I would just like the opportunity briefly to respond.

Mr. Mattingly has said that the trends of reserves additions disclosed by the AGA report is confirmed by the reports made on FPC Form No. 15.

Now, it has not been demonstrated that the information presented in Form 15 represents independently derived data unrelated to the source of AGA data, and it is only that kind of data that could be even remotely considered as confirmatory. Where you have data coming from the same source, one could hardly say that a re-report—two reports based upon the same

[4,760]

data confirm each other, even if they came out with the same result, because you have not demonstrated that the underlying data on which those conclusions are based is reliable.

Mr. Mattingly argues that if the AGA data were not received there would be an enormous burden placed upon the staff of the Commission.

[4,760]

Testimony of John C. Jacobs

Mr. Examiner, it was 1954, 16 years ago, the Commission was charged with the responsibility of regulating producers. It has had 16 years within which to collect information independently, objectively collected information, objectively evaluated information, and it hasn't done that. And it hardly seems to me that the Commission or its staff can argue that because of the Commission's failures you should now receive information that has not been subjected to the kind of analysis we are entitled to have.

PRESIDING EXAMINER: All right. The principal objection to the admissibility of Exhibit 49 for identification at this point is to its claim of confidentiality and the inability to go behind the figures to find out where they come from and what is behind them. Insofar as confidentiality is concerned, the Commission itself with respect to the figures on uncommitted reserves which are being used in this proceeding has accepted and respects the confidentiality of the producers. And I would apply the same principle to the figures to which confidentiality is claimed in this Exhibit 49 for identification.

[4,761]

Aside from the issue of confidentiality, if I were to apply the rule which is set forth in Rule 1.26 of the Commission's rules of practice and procedure, which states that evidence of a kind which would affect reasonable and fair minded men in the conduct of their daily affairs must be accepted or admitted, a quick check shows me that it is used by—these AGA figures are used by Government agencies; the Bureau of Mines of the Department of Interior in its Minerals Yearbook, which is issued yearly, uses these figures and relies on them. If you can refer to page 727 of the 1968 Minerals Year-

book, you will find reference to it there. You will find reference to the estimated productive capacity of natural gas in the United States as of December 31, 1968, on Table 9 of the same volume.

Furthermore, these figures are used extensively by the Power Commission itself in its new gas costing technique to determine additions to reserves. The AGD has sponsored a witness—the Associated Gas Producers in the South Louisiana case sponsored a witness by the name of Roseman who used the AGA figures in determining nation-wide cost of gas well gas.

In the Permian Basin decision of the Commission, I find reference which is reported at 34 FPC 159, at page 197; there is a sentence which states the total reserves added were derived from the AGA proven reserves statistics.

Now, this is enough to prove to me that this is the type of a reference, the type of figures or the type of a report

[4,762]

which would affect reasonable and fair minded men in the conduct of their daily affairs, and I am therefore admitting into evidence Exhibit No. 49.

(THE DOCUMENT PREVIOUSLY IDENTIFIED AS EXHIBIT NO. 49 WAS RECEIVED IN EVIDENCE.)

MR. GOLDBERG: Mr. Examiner, may I ask in view of your ruling that you direct that the sponsors of Mr. Jacobs and of this exhibit, the UDC make available the underlying materials, committee reports, work papers to the New York Commission—I am sure they would be interested in it—to the municipal group, and anyone else who wishes to use that material. Not only with respect

to Exhibit 49, but with respect to the preceding five years as well.

Nothing that the Examiner has said about accepting this material because in the Examiner's view others have used it and therefore others are reasonable and it is reasonable to conclude that this affects reasonable minds precludes our right to get behind this exhibit. And we therefore ask that you grant our motion and direct that that information be made available.

PRESIDING EXAMINER: I will not so direct.

Who is our next witness?

MR. HARKAWAY: If Your Honor please, a procedural matter that ties in with this witness' testimony.

PRESIDING EXAMINER: Which witness?

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[4,772]

TESTIMONY OF JOHN G. WINGER

* * * *

DIRECT EXAMINATION

BY MR. T. JONES:

Q. Would you please state your name and business address.

A. I am John G. Winger. My business address is 1 Chase Manhattan Plaza, New York City.

Q. Are you the same John G. Winger whose prepared testimony appears in the record in this proceeding beginning at transcript page 1452?

A. I am.

Q. Are the answers given therein the answers you would have given if these questions had been asked to you orally?

A. Yes.

Q. I invite your attention to a document entitled "Consumer Price Trends" which has been identified as Exhibit 20 in this proceeding. Was this prepared under your direction and supervision?

A. Yes, sir.

MR. T. JONES: Your Honor, I move the admission of Exhibit 20.

[4,773]

* * * *

THE WITNESS: Well, since this material was submitted we have conducted further study of the future energy requirements of the United States. This testimony was based upon a very detailed study prepared

in 1968, and it has become apparent since that time that the forecasts for all forms of energy were too conservative. Therefore, we have gone back and reviewed all of the work that was done and are now convinced that the re-

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CROSS-EXAMINATION

BY MR. GOLDBERG:

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[4,781]

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THE WITNESS: We use the AGA report for our economic studies. I use it all the time in analyzing the relationship between reserve additions and capital expenditures devoted to the search.

PRESIDING EXAMINER: Do you find that you can rely on them?

THE WITNESS: Yes, we do rely on them.

BY MR. GOLDBERG:

Q. Do you rely on it because you have a choice of materials that are available to you, or that is the only thing you have got available to you?

A. I think I might respond by citing a parallel. We also use a large number of the indicators of the Federal Government; and I might say that some of those are more suspect than the AGA numbers. Yet we rely upon them because that is what we have.

Q. I am glad you said "more suspect", because that implies that maybe the AGA could be suspect, too.

A. I would say that if we had to have numbers that we could feel were perfect, we might just as well go stand in a corner or go fishing.

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[4,786]

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A. Well, this is in the same sense that we began to be concerned about fifteen years ago over a shortage of gas. We pay a great deal of attention to the momentum of change when we deal with the energy market, and it did become apparent at that time—we saw the shadows of a shortage.

Now, it is necessary in our activities to look on down the road ten, fifteen years, because capital expenditure

[4,787]

programs usually cover that period of time. And in looking ahead, we see the matter becoming critical, and we are currently advising our customers that it will become critical. Critical in the sense that they won't get all the gas they want. Many potential end users will get none.

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[4,788]

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A. Well, as I did point out in the testimony, there were various financial factors in the past, dating back into the Thirities, and for a period of about ten years after World War II the petroleum industry was experiencing rapid scale price appreciation.

If I may say it in this way, in that ten-year period the actual wellhead value of oil and gas production in-

creased at an average rate of $600 million a year. Now, something more than 400 million of that was the result of price appreciation. The price of gas went up too, but something that is next to nothing doesnt' add up to very much in any event.

Well, in the mid-Fifties, by that time there was—well,

[4,789]

first there was a slowdown in the economy which can be tracted to demographic factors, a slowdown that lasted until the early Sixties. This was the time when the flood of gas came into the energy market and provided for the producer very little revenue. The gas was displacing oil that was a source of revenue, and we could see an abrupt change from our studies in the generation of capital funds. And the petroleum industry being characterized as a high-risk industry has always found it necessary to generate most of its funds for capital and other requirements, debt service and dividend payments, from its operations.

Since the industry had moved into an era when it was unable to generate at the rate it had been in the past, it became necessary to curtail capital spending, and that is exactly what happened.

Q. Well, let's get this much clear: When these first signs became apparent about fifteen years ago that you have just described, they were not FPC-related, were they? Federal Power Commission related?

A. Well, I don't know that I could say that without knowing the thoughts that went through the minds of all of the individual producers, the major companies who constitute the industry.

I would not want to say that the 1954 decision and the other developments prior to that did not influence the industry.

[4,790]

The utilization of capital—the decision to utilize money is based upon many factors which might be put into three categories: Geologic, economic, and political. And we had two factors that went bad for the producer. His geologic factors remained good, but the economic factors were poor because very little oil was going into the market. The political factors went bad as a result of this decision; also as a result of the two actions of the administration in the past which went against the interests of the producer.

Q. All right. With respect to the economic factor, you say very little oil is going into the market. Now was that because of the petroleum industry?

A. The petroleum industry was making available petroleum hydrocarbons, both oil and natural gas and the liquids therefrom. And as I indicated in the testimony, less than one—or approximately one-fifth of the market growth was captured by oil, a major part of it by gas.

Q. All right. Now, was that because the industry was promoting the sale of gas in competition with oil?

A. I would say for a time the independent producers were making all the gas available and actually promoting. The independent producer is not in a position to make an economic analysis of the energy market. I would say also in the early years immediately following World War II that very little of the industry was really looking into the future and

[4,791]

measuring the impact upon its overall operations that stem from the great amounts of gas going into the market. It took some time for this to become known.

Q. With respect to the majors, were they promoting the sale of gas over oil?

A. As a group—I can't say for all majors, but as a group they were in the earlier years, until it became apparent that this was financially not proper action to take.

Q. In other words, you are saying that by promoting the sale of gas over oil they were reducing the amount of funds available for capital expenditures for exploration and development from internally-generated sources. Is that right?

A. Well, I think we have to add an additional factor. I don't like the term "promoting." I imagine all of us in this room are familiar with the ruling of the Texas Railroad Commission shortly after World War II that the flaring of gas had to stop. We all recognize it was a great economic waste. And simply stated, the ruling was that either the gas had to be sold for some economic purpose or returned to the reservoir. Returning it to the reservoir entailed additional capital expenditure without any promise of return. So the producers, large and small alike, were willing to sell the gas at that time. I say willing, without having measured the full impact in the market in the energy market. But then it became apparent that this was not the thing to do. The production of

the gross revenue dollar that flows from the sale of gas is so very small there could not possibly be any profit from it when it was displacing a liquid product.

Q. Does it come down to this then: That the ruling of the Texas Railroad Commission forbidding the flaring of gas forced producers to sell that natural gas, but they would have been wiser if instead of selling it they had

taken a long-range view of the effect of the sale of that gas on capital available to them and have returned that gas to underground reservoirs?

A. Economically it would appear to be wiser, yes. Whether it would be physically possible for them to have returned all of the gas to the reservoirs, I can't say.

Q. Is it your testimony that if the market for oil is such that the price of oil is depressed, which in turn cuts down the amount of money available internally for exploration and development, that the price of gas must then make up the deficiency created by the depressed price of oil.

A. Well, it was the amount of gas coming into the energy market at a price very much lower than any price that could be justified for a refined product that depressed the price of oil. Number Two heating oil had to compete with this gas, and only in one small corner of the nation was it able to compete on a price basis. So that price was held down. To the degree possible, the price of gasoline, which is not affected by this

competition, was inflated. But the industry—too many elements of the industry attempted to find relief in the transportation market, and the intense competition there kept the price of that down.

Q. But if I understand your testimony, it is that if the requirements for funds doesn't come out of the sale of oil because the oil prices are depressed, then it has got to come from the sale of gas at a price level that makes up the conditions in the oil market?

A. Well, the two are not quite the same, because in the case of oil, for a producer, a producer alone, his gross revenue comes from the sale of crude oil. For the integrated company, his gross revenue comes from the sale of refined products to the ultimate consumer.

I can say to you that the revenue that can be traced to the sale of gasoline is equal to sixty percent of all gross revenue, and that the revenue that comes from the sale of natural gas is less than five cents of the gross revenue dollar.

So it is a very complicated industry, and we can't trace the revenue source through and say that this is the case for all of the industry, because it is different for the different components of the industry.

Q. Well, if I understand what you have just told us, you are saying that even with increased prices of gas, which would generate more funds internally, it represents a very

small fraction of the internally-generated funds that are needed to keep exploration and development at an appropriate level.

A. Yes.

Q. All right.

A. May I elaborate on that?

Q. Yes.

A. I will use myself as an example. I am a consumer of gas, and I will pay at the point of consumption about $1.50 per Mcf.

Now, all that the petroleum industry gets from my dollar and a half is what the producer receives at the wellhead, roughly ten percent or slightly more than that.

If I were using oil instead and paying the same $1.50, approximately half of it, or 75¢ would go back to the producer and the other 75¢ would go to the other integrated activities of the petroleum industry. So the financial residue from my $1.50 spent for oil is very much larger than the $1.50 that I spent for gas. And it is from that financial residue that the producer is

able to devote a greater financial effort to the search for both.

Q. So you are saying that the producer, from the viewpoint of having sufficient internally-generated funds, is better off selling the oil than he is selling the gas, but he was forced to sell the gas because of the Texas Railroad Commission's

[4,795]

ruling against flaring.

A. Well, that is part of it.

When he embarks upon a search for petroleum reserves, in most instances he is motivated by his desire to find oil, not gas. He wants to find the most valuable petroleum hydrocarbon.

But the record indicates that for most of the time since World War II, for every dollar invested in the search, he has found almost equal amounts of dry gas and liquids, a combination of crude oil and gas liquids. And since that is the result, he has the gas and he must sell it.

Q. I don't know that I have an answer yet to one of the questions that I have been asking, and I would like to try it this way. It is probably my fault, not yours.

Since the sale of gas doesn't provide as much internally-generated funds for exploration and development as the sale of oil does, something needs to be done about the price of gas so that gas will make a greater contribution of internally-generated funds for exploration and development. Is that correct?

A. Exactly. Must have.

Q. Now, if the price of gas is increased and thereby produces a greater reservoir of funds for exploration and development, the producer is nevertheless going to be interested in developing—or in searching for the most valuable product, and that would be oil, right?

A. That's correct. For the time being.

Q. Yes. And you know of nothing, do you, that would compell him to devote the money, greater internally-generated funds resulting from increased gas prices, to the search for gas?

A. Well, iff his incentive to conduct a more active search increases, if he looks for oil and if his results in the future are the same as they have been in the past, he is going to find gas as a result of the search for the oil.

If there should be changes, economic changes which would give him an equal incentive to search for gas, to some extent we believe that a directional search may be maintained. But only to some extent.

Q. Do you have any idea of the level to which the gas prices would have to be raised to provide that equivalent incentive?

A. May I give you a lengthy answer to that, to repeat part of what I said here, because I think it is very important.

Q. If you can't give me a short one, give be a long one.

A. All right.

We are talking about an industry, industry averages, and individual company experiences will vary substantially from this.

But our records indicate that there has been a consistent relationship since World War II between the reserves of oil

and gas added and the dollars invested—capital dollars and exploratory dollars.

Because of this longstanding relationship, and also because the amounts of gas and liquids have also been equal, this gives us a reasonable basis for projection. We believe as a result of our studies that we can make realistic measurements of the future energy requirements of the nation divided between the various sources of energy. This will give us the quantities of oil and gas required. And we can relate to these quantities, then, the capital expenditure that would be needed to provide that amount, assuming that the industry could have the same success as it has in the past.

Well, this suggests to us that immediately the industry would need to spend approximately $3 billion more annually. How might the industry generate that much more? Well, we could start out by using ten cents, because it is an easy figure to work with. Ten cents more for all gas, new gas and flowing gas, that would generate slightly more than $2 billion additional wellhead value. After taxes that would leave somewhere between eight and nine hundred million dollars that could be potentially available for reinvestment. I say potentially, because we can't be assured that every producer is going to use the funds in that fashion.

That then would be less than one-third of the indicated amount required. But, if the price of gas were to advance,

[4,798]

it I think is a very good likelihood that the price of oil products would move up too, that the price of the competing oil products would move up and that the price of crude oil would move up. But if the job is to be done, that is the order of magnitude in the capital required.

That is just for the first year. It would have to increase thereafter.

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A. We have a regulation of the price of gas, as we all know, and this has constituted an indirect regulation over the price of competing refined products and the price of crude oil.

Now, if the regulation is changed or removed, then that would have an upward push to the price of domestic crude oil.

Now, coming to the international market, there are various reasons for believing that the world price of crude oil may

have bottomed out and will be moving up from now on. One of the reasons for this is that our dependency upon certain parts of the world has increased to the point where they have very great bargaining power and can insist upon higher prices.

Q. When you speak about the regulation of gas having an indirect regulatory effect on oil, are you saying that the price of oil is influenced by the regulatory price established for gas in terms of ability to compete?

A. That's correct.

Q. Would you refer to page 1455. In that sentence appearing in the first paragraph of the answer which begins: "It was the industry's overall inability," et cetera, you are there talking about the interdependence of oil and gas and that a shortage of one or the other or both is a combination of factors that affect oil production and gas production?

A. Yes. The interdependence is in there all the way through from the first search to the final sale in the market place.

Q. And that refers to all of the incentives that may be available to a producer in connection with exploration and development activities—I am thinking, for example, of tax laws. There too there is an interdependence?

A. Yes.

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[4,801]

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Q. Doesn't your testimony at pages 1457 and 1458 mean that one of the major factors which reduced exploration in the United States was the large increase in imports of foreign oil at the expense of the domestic crude?

A. That was a factor, yes.

Q. Would you call it a major factor?

[4,802]

A. Secondary to the gas factor.

Q. But nevertheless, a major factor? An important one?

A. An important one, yes.

Q. Yes.

Does your testimony at those pages also suggest that higher prices for natural gas twelve or fifteen years ago would have increased the drilling for hydrocarbons in the United States?

A. I don't think there is any doubt about it.

Q. But you are not suggesting by that testimony that the effort would have been to produce more gas; is that right?

A. Well, I think that if we could depend upon the evidence from the past, a greater amount of money spent would have resulted in a greater discovery of gas.

Q. But because gas was associated with the search for oil and the producers would be looking for this more valuable hydrocarbon, namely oil; is that right?

A. They would be looking for the oil, but as a by-product of that effort they would have found the gas.

Q. So that increased exploratory effort for oil as a by-product would have increased gas reserves?

A. Right.

Q. Would that increased effort have been influenced by projections of demand for gas?

A. Well, if we could presume that as the result of a higher price for gas that the market growth would have been

[4,803]

somewhat less, then the market growth for oil would have been greater. And there would be a double edge then to the increase of revenue, more coming from the gas, even though the volume was smaller, and more coming from the oil because the volume of oil would be larger and also the price would have been higher, had the price of gas been higher.

Q. Does your answer then mean that estimate of the demand for gas was an irrelevant factor in connection with drilling effort?

A. Well, going back to that period of time, there were estimates relating to the future requirement for oil which proved too optimistic because the industry was under estimating the competitive impact of the gas. More gas came into the market than had been thought at the time:

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[4,806]

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Q. You speak of the industry being an industry that relies primarily on internally-generated funds for their exploratory and development efforts; yet they do borrow money, right?

A. They do.

Q. And they borrow money because they want to mount an effort which can't be mounted solely from internally-generated funds; correct?

A. That's correct.

Q. And would the borrowing of funds for such

[4,807]

strike that and let me start over.

Are you here today indicating any limit on the borrowing capacity of the producers?

A. Very definitely.

Q. Now, what is that limit?

A. All right. As I said earlier, the industry did generate most of its funds for financial requirements from operations until about 1960. From that point on, there has been a steady decline. Now, when I am speaking of the industry here, more specifically I am talking about this group of major companies that we have studied for many years, and I am referring to their worldwide operations.

Well, throughout the decade of the Sixties, they experienced a steady deterioration in their ability to generate sufficient capital funds, and in the most recent year for which we have numbers, 1969, the industry found it necessary to go to the capital markets for about twenty-eight percent of their needs.

[4,807]

Testimony of John G. Winger

Now, we need to bear in mind that the industry's capital expenditures are in many areas. We might, for the sake of simplicity, talk about production expenditures and expenditures beyond the wellhead. There has been no change in production expenditures since the mid-Fifties with the exception of the outlay required for making the lease bonus payments in recent years to state and Federal governments. There has been

[4,808]

no increase in the expenditure devoted to the actual search for petroleum hydrocarbons.

On the other hand, the industry has increased expenditures for all other purposes: For transportation, for refining and for market. It has also increased its expenditures abroad relative to the outlay in this country.

Now, capital is very mobile, and when any of the three factors that I mentioned earlier become unfavorable, capital will indeed take flight, and much more quickly today than at any time in the past, because on a worldwide basis there is a shortage of capital, a shortage of capital facing the worldwide economy. This means that the petroleum industry must compete more vigorously for borrowed capital than it has ever had to in the past.

And I can say to you that one of the hardest things for a banker to do is to say no to a perfectly sound loan. Yet bankers throughout the nation and abroad have had to do that.

Q. Because of shortage of funds?

A. Because of a shortage of funds.

Q. You said that the production expenditures have not changed since the mid-1950s except for increases due to lease bonus payments. Were you talking about production expenditures in the Forty-Eight States?

A. That's correct.

Q. But production expenditures abroad did increase?

[4,809]

A. No, they have also stayed level. There was not the need to increase them abroad as there was in this country, because of the prolific nature of the discoveries in the Middle East and North Africa.

* * * *

[4,811]

* * * *

I might add that lease bonus payments are a new element of cost that is likely to be in the picture from now on, not only in the United States but in the rest of the world as well. It could very well detract from the actual expenditures devoted to the search.

Q. You say a new element of cost.

A. Yes. In other words, it is an increased flow of funds

[4,812]

from the industry to governments.

Q. In the United States has that developed in connection with offshore exploration and development? Federal leasing?

A. It started with offshore. It has taken various forms on government lands in the past. In Alaska it was not offshore.

Q. In other words, these are payments made to the government, which payments are not therefore available to the producers for exploration and drilling efforts?

A. Well, it is money that the government is charging the producer for the use of the land, for the right to conduct the search.

Q. And these charges tend to reduce the available funds for exploration and development?

A. Yes, they will, if the industry is unable to generate that much more.

Another reduction, of course, was the change in the depletion allowance last year, which reduced one of the industry's provisions for capital recovery.

Q. To the extent that changes in the depletion allowances reduced the amounts available for exploration and development effort, you are saying, are you, that the funds have to be produced some other way and if isn't to be done through borrowing, it has to be done through raising prices to increase the amount of internally-generated funds. Is that

A. Yes. Historically, of the funds generated from operations, approximately half was derived from net income and the other half from the various provisions for capital recovery. So if the latter goes down, then the industry must try to make up that deficit in net income, which of course would mean higher prices.

Q. With respect to the expenditures made abroad, do you know whether they were made abroad because they offered the industry greater profits than might be available from domestic exploration?

A. That would be part of it. If I might again go back to the three factors. Starting with the geologic factors, there are many areas of the world in which the petroleum industry might conduct a search for petroleum, a promising search. The growth potential for petroleum outside the United States is very much greater than it

is within. Western Europe and the Far East are two parts of the world that are likely to be seen to have great growth. So that means the economic factors are favorable.

The political factors change frequently in various parts of the world. To provide you with one example, in 1958, the Venezuelan Government imposed a much higher tax on the industry, which precipitated a flight of capital. That capital moved around to various parts of the world.

Now just to bring us up to date, we have had other

[4,814]

developments. I am referring to the discovery of—important oil discoveries in the North Sea by two companies, combinations, and then even more recently a major discovery in Southeast Asia. Just as sure as we are sitting here today, there are meetings in various corporations reallocating budgets. If the budget doesn't increase, the funds have to be diverted from activities in some part of the world to another. And it is most likely that these funds would have to come from North America.

I say North America, because Canada would be affected as well.

Now, on your point on profit, currently and for most of the past since World War II the rate of return on average invested capital has been higher abroad than in the United States.

* * * *

Independent producers have cut their capital outlay in

[4,815]

the United States to one-half of what it was in the mid-Fifties. Now, we are unable to say where they are em-

ploying capital. There are many opportunities open to the independent producer these days, particularly since we are in an era of capital shortage.

Q. To the extent that higher profitability for effort is available abroad, you would expect that the increased funds generated by higher prices would tend to be used by the industry in such areas, wouldn't you?

A. Not if the increased prices improve the rate of return in the United States relative to what it might be abroad, and also taken in the light of the various political risks encountered about the world.

Q. In other words, you are saying that the comparative profitability must take into account the comparative risks involved?

A. That's correct.

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[4,818]

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Q. Would you say that the total level of expenditures during the period 1956 to 1969 for finding and developing gas and oil reserves was a function of the total revenue derived from oil and gas production?

* * * *

THE WITNESS: It is a function of it, but it is not the only factor involved, because the investor may in considering his alternate opportunities for investment conclude from this level of investment that he would dedicate part of his revenue generation to another form of investment. This obviously is what has happened to the independent producer.

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[4,823]

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If the producer is going to put his money where he has the promise of greatest return and regulation does not establish prices based upon such a philosophy, isn't the producer always going to put his money where there is this promise of greatest return regardless of the increase in prices regulation gives him?

A. Well, I think all forms of regulation, whether it is the price of natural gas or banks or railroads or whatever, must recognize that financial capital is a resource, too. And it is not in plentiful supply. And there is competition for the available capital. And if there must be regulation—and I don't say that we should do away with all regulation, but rather that enlightened regulation would recognize this fact and thereby provide regulation which would permit the industry to compete effectively for capital.

And under those circumstances, then, the producer

[4,824]

utilize the funds for the purposes you have in mind.

* * * *

[4,829]

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Q. Is it the sense of your testimony on page 1459 that beginning in about 1956 and down to the present time domestic crude oil has been overpriced in relation to its cost and natural gas has been underpriced in relation to its cost?

A. One might reach that conclusion because of the inability to segregate the cost. And there is a tendency

when costs aren't known to relate them to revenue received. So we had in effect, then, gas going into the energy market bearing a very small price tag and little of the cost burden and displacing oil bearing a high price tag and most of the cost burden.

Now, under different circumstances, if there were a higher price for gas, conceivably the price of oil could have been lower, up to that time, but not since that time.

Q. You say that one might reach that conclusion. Is that the conclusion you want one to reach from your testimony at transcript 1459?

A. No, not necessarily.

[4,830]

The conclusion I would want people to reach is that the generation of capital funds from that point has been too small.

Q. Even if domestic crude was properly priced, your conclusion still would be that there should have been a greater contribution to the revenues needed by the natural gas price?

A. From 1956 on.

Q. Yes.

A. Yes.

* * * *

[4,837]

* * * *

Q. Would you say that if both domestic crude oil and natural gas had been priced to recover the costs properly

[4,838]

attributable to each, that the growth in gas demand since 1956 would have been substantially less than was actually experienced?

* * * *

[4,839]

* * * *

THE WITNESS: This hinges upon the term a proper allocation of costs. And I can only give what I would consider to be proper. And that would mean an allocation of the costs that related to the intrinsic value of the hydrocarbons found. And under those circumstances, the price of gas moving into the energy market for all and uses would have been substantially larger than it actually was, because the cost so attributed would have necessitated a higher price. And even so, I do not believe that the volume of gas going into the market would have been very much less because the gas did move into the energy market at a price far below that of competing sources of energy. The gas in addition to a comparison of Btu costs has other values to the consumer.

[4,842]

* * * *

Q. Yesterday you mentioned in response to a question I had asked you about the limits on the borrowing capacity of the producers, you indicated that majors were going to the capital markets for about twenty-eight percent of their needs. And if you want to refresh your recollection about this, you might look on pages 4806 to 4807 of the transcript yesterday.

Did you mean by that testimony to indicate that the majors could not expect to be able to borrow more than about twenty-eight percent of their needs in the capital market?

A. There is no way of knowing to what extent the proportions will change.

[4,842]

Testimony of John G. Winger

I would say certainly the major companies are and will continue to encounter increasing difficulties in obtaining funds from the capital market.

We must also recognize additional factors.

The petroleum industry goes in heavily for so-called off-the-balance-sheet financing. A major part of this would be

[4,843]

service station lease-back arrangements.

Now, these are obligations to pay. They are really a hidden form of debt. It is a method of financing in lieu of a capital expenditure. This, then, if we consider it as a part of the debt, would increase the major companies as a group—it would increase their debt-to-equity ratio. And that then would indicate further that the industry has perhaps reached the limits.

We increasingly hear now comments from management that they will not borrow additional funds for capital expenditures. They are going to live within their means.

Further, we need to recognize that borrowed capital is an expedient taken for the purposes of timing, but in the long run all borrowed funds must be repaid with funds generated from operations.

Q. Isn't it the fact that whatever limits there may be on the producer's ability to borrow capital, those limits stem from the capacity of their operations other than natural gas to generate funds?

A. Well, it is limited by their overall ability to generate funds.

Q. But in that picture of the overall revenue, natural gas is a very small part; isn't that right?

A. It has been a small part.

Q. Yes.

Yesterday we mentioned it was less than fifty percent of the total revenues.

A. No. Of the total revenue generated—and we must go beyond the wellhead, because the funds are generated as a result of the operations from the first time money is devoted to the search to the final sale to the ultimate consumer.

Of the total gross revenue generated from all operations, the sale of natural gas accounts for less than five percent.

Q. Well, doesn't that mean, then, that whatever limitations exist on the ability of producers to borrow capital in the markets stems from the generation of funds by their operations other than the natural gas operations since the rest of it represents about ninety-five percent of their revenues?

A. It would stem from their ability to generate funds from all operations. For the independent crude oil producer it will generate from his sale of oil and gas at the wellhead. For an integrated company it would flow all the way through from the sale of all sorts of petroleum products.

Q. But with respect to the contributions of natural gas revenues to the total gross revenues of only five percent, doesn't it follow that the revenues generated by the sales of gas play a very small part in the ability of the producer to borrow capital in the market?

A. They have in the past, and that takes us right to the core of the problem.

[4,845]

Testimony of John G. Winger

[4,845]

PRESIDING EXAMINER: Of that ninety-five percent remaining, what percent of that is derived from the sale of petroleum or petroleum products only?

THE WITNESS: Well, all of the ninety-five percent, approximately sixty percent of the gross revenue can be traced to the sale of gasoline alone. And we have in the neighborhood of eight to nine percent that can be traced to the sale of petrochemicals. And the rest would be the sale of light and heavy fuel oils.

* * * *

[4,853]

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When the gas, however, began to reach all of the energy market, it could no longer be considered in a by-product status. But, from the standpoint of contributing financial results, it is still in a by-product status.

Q. Referring to your testimony at the top of page 1461—and I am particularly referring to lines five down to the end of that paragraph.

Are you there saying in effect that on the basis of Btu content gasoline sells for about twenty-four times as much as natural gas in the field?

A. Well, I haven't made the calculation in that way. It would be the relationship of the five cents to the sixty cents of the revenue dollar.

* * * *

[4,858]

* * * *

A. No, sir. The maintenance of reserves of both liquids and gas was satisfactory from the standpoint of the na-

tion's energy requirements up until the Mid-Fifties. There has been

[4,859]

progressive deterioration since that time for both liquids and gas.

Now, it is important to measure the inventories, and proven reserves are in the nature of inventories. For any commodity inventories must remain in a satisfactory relationship to the expansion of the market, and we utilize a reserves-to-consumption ratio.

The ratio for liquids has been poorer than for gas for a longer period of time. But these are both trends that obviously cannot continue indefinitely. They have run just about as far as they can, in my opinion.

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[4,862]

We do believe that the reserve-production ratios are now at minimal levels, both for liquids and for gas. It is important to bear in mind that the gas industry as an industry operates under a much higher debt-to-equity ratio than the petroleum industry. They are able to do that because they are a low-risk industry.

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[4,888]

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Q. Mr. Winger, you testified earlier that as a result of a change in projections as indicated by later developments you have revised some of your earlier studies. And I would assume you can indicate the extent to which this is true. Some of the figures—and I would call your

attention particularly to this $150 billion figure on page 1463—may have changed. Is this a figure that will have changed as a result of that change in the forecast from 1985 pushing that date forward to 1980?

A. It would depend upon the assumptions made in that particular position.

If we were to set as an objective an expenditure necessary to satisfy all of the nation's requirements for oil and natural gas without becoming proportionately more dependent upon outside sources, then the figure would have changed. It would have increased.

Q. As a result of your testimony that you gave this morning, would you now change this $150 billion figure?

A. Yes. It would be higher under those circumstances.

Q. Could you give an indication of approximately what range, the order of magnitude of that increase would be?

A. I could readily do it if I had the data before me. I do not have the number in mind.

Q. Would it be substantial in comparison with the $150 billion?

[4,889]

A. It would be substantial.

Q. Now, just to be—

A. I can elaborate on that if you wish.

Q. Certainly, by all means.

A. We have tried to measure all of the sources of natural gas from domestic and foreign sources, and as a result we have concluded that by the end of this decade, if there is no increase in the level of spending, that there will be a deficit amounting to 30 billion cubic feet a day.

Now, this deficit has to be filed with some other source of energy. The other sources will be oil and coal, most likely. That, then, enlarges the demand for oil substantially over what we would expect under more nor-

mal circumstances. And if the industry is motivated primarily to find oil—and I underscore "if"—then that is going to increase the expenditure very extensively. It would have as a by-product, of course, the additional discovery of gas.

Q. Now, this 150 billion which I assume now is a minimum figure as a result of your earlier testimony, just for my own understanding, that is an investment that is required domestically, in the domestic industry?

A. That is correct.

Q. Solely. And it represents investments that are made exclusively in the production function. There would be no investments here in transportation, marketing, refining, any of

[4,890]

those things?

A. No, sir.

Q. It is all in the production function?

A. Strictly production.

Q. Mr. Winger, in making that estimate did you attempt to quantify or consciously include or exclude the Alaskan hydrocarbon province?

A. Yes, Alaska is included. The discovery of oil on the north slope of Alaska meant that additional capital funds would be devoted to that area. But it did not result in any increase in the available capital. It meant that these funds would have to be diverted from an activity somewhere else, most likely within the lower 48 states.

So when we speak of domestic expenditures we do indeed have all of the states included.

Q. Now, I would like to have at this time—I think it may have been stated in your testimony. I don't have the figure exactly in mind. On the average, investment, as

you define that term, in the domestic petroleum natural gas industry has not changed over the past ten years. What has that level been? What is the current level?

A. The level of spending?

Q. I would say the current level, yes.

A. Well, I must qualify that.

The level of spending over this period has averaged about

[4,891]

four and a quarter billion dollars, of which approximately 700 million represented leasing costs.

Now, the latter has doubled in the last two years. So the current level of spending now is approximately $5 billion, and from your testimony on 1463, it appears that the minimum—under your testimony the minimum for the foreseeable future will be at least 10 billion a year. Would that be a fair statement?

A. That is correct. That is an average, starting with seven billion, reaching approximately 13 billion by the end of the period.

Q. So that the average deficiency at the present time would be approximately five billion?

A. That would be correct.

Q. Now, you have touched on the subject of how that five billion is to be accounted for, where the additional five billion will come from. And as you indicated earlier in your cross-examination, if prices for flowing gas, gas which is on stream at the present time, were increased 10 cents per Mcf, you would generate approximately $2 billion.

A. In gross revenues.

Q. In gross revenues. So that would essentially be wellhead revenues, would it not?

A. That is true.

[4,904]

* * * *

Q. Now, would this analysis be the type of analysis that would provide evidence or indicate whether or not gas was

[4,905]

adequately priced, overpriced, or underpriced in the various end use markets?

A. To our satisfaction it provided evidence that it was very much underpriced.

Q. In which markets is it underpriced?

A. In all of the markets.

Q. Is it underpriced—

A. Residential and industrial, or boiler fuel markets.

Q. Is it underpriced in some more than in others?

A. Yes, sir.

Q. Which is the most underpriced, then?

A. It would be—it is easier to answer that the other way around. It is least underpriced in the northeast section of the nation.

MR. GOLDBERG: Gas is lease underpriced—

THE WITNESS: Gas is least underpriced in that area.

MR. GOLDBERG: That is where it costs most?

THE WITNESS: That is where it costs most.

This, again, will vary for specific cities. The cost of gas in the metropolitan area of New York is very much greater than the cost of gas in Albany, yet Albany is further removed from the source. This has much to do with the local distribution costs.

BY MR. MATTINGLY:

Q. What about in the industrial markets?

[4,906]

A. In the industrial market the cost of gas was lowest nearest the source of production. In other words, at the Gulf Coast. And this accounted for a heavy migration of industry from other parts of the nation to the Gulf Coast area.

If the price of gas were set on an economic basis, it would be most costly again in the northeastern part of the nation, but we know that gas has been sold on an interruptible basis for less than the cost of transporting it to the market.

Now, this is a necessary result of the kind of distribution where gas must be constantly on the move. And it reflects the difficulties in storing this form of energy.

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[4,908]

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It is our impression from our contacts that as the supply of gas becomes increasingly tight there will be a withdrawal from the industrial market to the extent that this is possible to prevent the greater proportion of the gas to be channeled to the residential market.

Industrial consumers do have somewhat more latitude in utilizing other sources of energy than the residential market. They may be unwilling to give up the gas, they may be very well forced to give up the gas, as several have told us that they have been told after cut-off date in the future when their needs can no longer be provided. And this naturally would be manifested in an interest on the part of industrial consumers to pay more to retain the supplies of gas, to compete more effectively with the consumer—residential consumer for available supplies. Now,

these are impressions based upon contacts. We have no way of documenting this at the moment.

[4,916]

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A. I wish I knew. We can't see them. We can't see the petroleum industry generating enough for its own purposes. The overall financial requirements of the petroleum industry in the decade of the Seventies adds up to more than $500 billion. And if the industry had an annual growth in earnings in the Seventies equal to what it achieved in the Sixties this would not be nearly enough. It means a much larger annual growth in earnings than we have witnesses in the past and this is not likely.

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[5,127]

TESTIMONY OF CHARLES A. LARSON

* * * *

Q. Are you the same Charles A. Larson whose prepared testimony appears in the transcript of this proceeding commencing at page 2008?

A. Yes, I am.

Q. Are the answers given therein the answers you would give if you were asked the questions appearing in that?

A. Yes, with the exception of some changes resulting from a change in my Exhibit 37.

Q. Would you please describe the changes you would make?

A. The first change is at page 2017. The first full answer, Exhibit 37 should be changed to Exhibit 37 Revised.

Q. Has the revised exhibit been served on the parties?

A. Yes, it has.

PRESIDING EXAMINER: Instead of 37 Revised, let's make that 37-A.

MR. T. A. JONES: Very well.

(THE DOCUMENT REFERRED TO WAS MARKED AS EXHIBIT NO. 37-A FOR IDENTIFICATION)

THE WITNESS: The next change appears at transcript page 2019. The third line change 5.44 to 5.69. And on the same line change 4.12 to 4.21.

On the following transcript page, 2020, in the middle of the page is a reference to 31 percent. That should be changed to 29.1. And on the same line change 43.2 to 41.1.

[5,128]

And two lines below that, change 79.2 to 79.5.

On the same line, change 86.9 to 86.8.

I would like to make another change which resulted just because of the time difference, and that is the second line from the bottom I have testified in a second case for the Connecticut Natural Gas Corporation, so after the Docket No. 10833 I would like to add "and 10981." In other words, I have testified in two dockets before the Connecticut Commission for that company.

BY MR. T. A. JONES:

Q. Mr. Larson, could you tell us briefly the reason for the changes in the percentage numbers appearing on page 2019 and 2020 which you have just described?

A. The changes substantially result from a change in determining the growth rate, namely that I had used the linear least squares method to determine a line of best fit and hence a growth rate, and I changed that to an exponential lease squares method, which better approximates a growth rate. The linear method could be represented by the equation Y is equal to A plus BX. The exponential would be shown by the equation Y is equal to AB to the X power.

MR. JONES: Your Honor, I tender the witness for cross-examination.

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[5,162]

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Q. And how large an increase in the wellhead price could be piled on top of these other increases before some signs of elasticity would be shown under your theory?

[5,162]

Testimony of Charles A. Larson

A. Well, in this present very tight energy market where natural gas is not the only fuel which is in short supply, but oils is in short supply and coal is in short supply, it looks like a very substantial increase could be absorbed without a decline in the demand for natural gas.

In other words, so long as the price of fuel oil keeps climbing, the price of natural gas can climb right with it, with no diminution of the demand for gas. This is the present tendency, and I disagree with Mr. Frazier that it is short-term.

[5,163]

I think it is long-term, and I believe that is why all of these studies on the energy problems are being started, because this is a long-term problem for the United States. We have a very critical shortage of fuel and energy, and I believe it can continue for a long time.

Q. How long?

A. Well, certainly within the foreseeable future, like ten, twenty years. I would make studies to the year 2000 if I were studying energy supply and demand in this country.

Q. And in the meantime, would it be your recommendation that what the market would bear in terms of prices for all the fuels is what should govern?

A. Well, I would give considerable weight to what the market would bear in order to determine the price that elicited the required supply of gas.

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[5,164]

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A. I am only talking about a gas supply shortage in the field. I am not talking about a pipeline supply shortage.

Q. And do you mean a shortage of gas in the field to supply incremental interstate pipeline markets?

A. Yes. I am talking about a shortage to supply the additional demands for gas, these demands growing every year.

Q. By interstate pipeline companies?

A. Demands growing within the cities and being reflected in the demands for gas by the interstate pipelines, yes.

Q. What is the source of your information about the gas supply shortage?

A. From working with gas distribution companies in New England, it has been expressed by the managements of those companies that price is not the prime factor; that they want gas, and they are willing to pay substantially more for it. And most of them intend to get gas even if it is not pipeline gas. They are willing to spend large sums of money for alternative sources such as LNG, propane air, et cetera.

* * * *

[5,168]

Q. Going on to your next answer on the same page where you speak of the approximately 31 percent growth in the Gulf Coast area, why is the prospective growth so large in that one area?

A. In the Gulf Coast area the intrastate market has been growing rapidly so today the prices of natural gas are higher for the intrastate market.

Q. Why has this increasing intrastate growth taken place?

A. Well, just a number of reasons. There is a large population growth in that area. There is the Gulf area

where they have access to water transportation. There are just a number of reasons for the growth.

Q. And why is it that there is this large percentage of 70 percent of industrial use? Why does it exist on the Gulf Coast?

A. Well, certainly in large part because of the price differential.

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[5,174]

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And in my opinion, a small price differential would cause some of these intrastate customers, users of gas, to switch to alternative fuels.

Q. So the record is clear at this point, what would these alternative fuels be, specifically?

A. Well, in a power plant, largely No. 6 fuel oil. Power plants in Texas use quite a bit of oil. But in Louisiana they use almost 100 percent gas.

Now, with a price increase for natural gas, assuming no change in the price of oil, there would be a shift to oil in the generation of electricity in Louisiana.

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[5,178]

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REDIRECT EXAMINATION

BY MR. T. JONES:

Q. In answer to a question by Mr. Maris, you gave us the August 1970 price of coal. Can you give us the August 1970 price of No. 6 oil?

A. Yes. For low sulphur, maximum one percent, No. 6 fuel oil, low pour, New York Harbor barge delivery, August 1970 price of $3.60 per barrel posted. Similarly for no sulphur guarantee, $3.05 a barrel.

MR. MARIS: For clarification, what is the source of these figures?

THE WITNESS: Platt's Oil Price Handbook and Platt's Oilgram Price Service.

BY MR. T. JONES:

Q. You mentioned that when most of the natural gas —or most of the distribution companies on the East Coast converted from manufactured gas to natural gas that there was a rate reduction. Was that your testimony?

[5,179]

A. Yes, that is right.

Q. Do you know whether Philadelphia Gasworks reduced its rates when it converted?

A. Philadelphia Gasworks did not reduce their rates with the conversion to natural gas.

Q. You have been asked several questions concerning the pattern of load growth subsequent to the conversion of New England companies from manufactured gas to natural gas. I would like to ask you whether companies in the Midwest such as in St. Louis and in Chicago once upon a time had manufactured gas service?

A. Yes, they all had manufactured gas service.

Q. Is there a similarity between the pattern of growth in New England and the pattern of growth in those markets subsequent to the conversion to natural gas?

A. Yes. The patterns are similar. It is just a time differential. New England received natural gas later.

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[5,190]

FEDERAL POWER COMMISSION
BUREAU OF NATURAL GAS

Docket No. AR69-1, *et al.*

AREA RATE PROCEEDINGS, *et al.*
(SOUTH LOUSIANA AREA)

TESTIMONY OF LAWRENCE R. MANGEN

Q. Please state your name, by whom you are employed, and your position?

A. My name is Lawrence R. Mangen. I am employed by the Federal Power Commission in the Bureau of Natural Gas as a supervising natural gas engineer.

Q. Briefly outline your educational and professional background?

A. I received a B.S. degree in Engineering at the University of Minnesota in 1955 and a M.S. degree in Geology in 1957 at the University of Minnesota. Upon graduation I was employed by Shell Oil Company as a junior engineer, field engineer, workover engineer and production geologist. Since 1962 I have been employed with the FPC. I am currently Assistant Section Head, Gas Supply Section and I am also team leader of the National Supply Team of the Gas Supply Section of the Analysis and Procedures Division of the Bureau of Natural Gas.

Q. Are you a member of any professional societies?

A. I am a member of the society of Petroleum Engineers of AIME, a fellow of the American Association for the

[5,191]

Advancement of Science, and a registered professional engineer.

Q. Have you previously testified in any hearings?

A. Yes, I have testified before the Texas Railroad Commission, primarily on productive acreage hearings, and before the Federal Power Commission in two prior area rate proceedings, Docket Nos. AR61-2, (South Louisiana Area) and AR67-1 (Other Southwest Area).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe and explain the procedures used by the Commission staff in auditing the uncommitted reserve figures reported by the producers in this proceeding.

The Commission by its order of March 17, 1970 required producers to report certain reserve data by separate questionnaires for the Onshore and Offshore Areas in Southern Louisiana. The data were to be reported as of year-end 1968 and year-end 1969. Volumes of reserves available for sale and reserves held for fulfillment of warranty gas sales contract were to be reported for the Onshore Area. In addition to the reporting of volumes of warranty gas and gas available for sale in the Offshore Area, the Commission required the reporting of volumes of gas reserves committed to direct industrial contracts and the reserves held for company use and fuel or feedstock

[5,192]

but not subject to specific contract arrangements. The completed questionnaires were forwarded by each responding producer to the Tulsa, Oklahoma office of Arthur Young & Co. Donald W. Auten, a certified public account-

ant with that firm, composed the data and presented it in this proceeding as Exhibit No. 27. That exhibit has been a public record since May 26, 1970.

Q. Were the volumes reported by each individual respondent made public?

A. No. Under the Commission order, the individual company responses were to be treated as confidential information without public disclosure. However, that order also provided that the individual reports and data underlying such reports should be made available to the Commission staff upon request.

Q. Was a request for such an audit made?

A. Yes, it was made and an audit was performed.

Q. How was the audit performed?

A. The first step in the audit was to review all the individual company filings in order to verify the totals of the volumes composited by Mr. Auten in Exhibit No. 27. In order to maintain confidentiality I was selected as the only person who would see these filings.

Q. How was this done?

A. Each company could choose to mail or personally

deliver its filing to me at the Commission. Those not wishing to come to Washington had the opportunity to show their filing to me at the Federal Building in Houston, Texas on June 17, 1970. I then recorded the volumes of uncommitted reserves which each company had reported; stamped, dated, and initialed the individual filing; and returned it to the company.

Q. How did you determine whether these were the same filings that were used by Mr. Auten in compiling his composite for Exhibit No. 27?

A. Mr. Auten had marked each one with his initials and the word, "Composited."

Q. Why did you stamp, date and initial each filing?

A. First, I wanted to insure that I did not record the same information twice. Second, by marking each filing, the Staff member who would later be performing the audit of the company's reserves at its office would be assured that he was reviewing the same figures which I had earlier reviewed.

Q. How did you record the data from the individual filings?

A. I copied each of the volumes of reserves reported by every individual producer and composited these figures to arrive at the total volumes under each category.

Q. Were the composited totals of the individual filings which you reviewed identical to the final totals submitted

[5,194]

by Mr. Auten in his revised Exhibit No. 27-A?

A. There were a few variations primarily because several producers revised their filings and the final submission made to Mr. Auten may have differed slightly from the submission which I included in my composite. However, as the following table shows, any variance was of such slight magnitude as to have negligible effect on the outcome.

Mcf at 14.73

Onshore	As of Dec. 31	Exhibit No. 27-A	Staff	Difference (+ —)	%
Co. Use-Warranty Gas	1968	2,598,749,372	2,437,483,724	—161,265,648	6.2
Co. Use-Warranty Gas	1969	1,954,232,242	1,840,610,239	—113,622,003	5.8
Available for Sale	1968	1,269,943,375	1,268,833,375	— 1,110,000	0.1
Available for Sale	1969	1,508,980,877	1,505,861,614	— 3,119,263	0.2
Offshore					
Direct Ind. Contracts	1968	1,466,491,000	1,466,491,000	0	0
Direct Ind. Contracts	1969	1,405,614,000	1,405,614,000	0	0
Co. Use-Warranty Gas	1968	1,361,717,904	1,334,997,754	— 26,720,150	2.0
Co. Use-Warranty Gas	1969	1,812,212,673	1,777,365,960	— 34,846,713	1.9
Co. Use-F&F	1968	917,944,391	897,955,088	— 19,989,303	2.2
Co. Use-F&F	1969	962,372,648	944,041,574	— 18,331,074	1.9
Available for Sale	1968	3,307,456,660	3,300,572,756	— 6,883,904	0.2
Available for Sale	1969	1,094,606,960	1,100,846,423	+ 6,239,463	0.6

[5,196]

Q. After verifying the individual components of the Auten composite, did you proceed to audit the data underlying the uncommitted reserves volumes as submitted by each producer?

A. Yes. I arranged to have members of the staff visit each company that reported having any uncommitted reserves in Southern Louisiana.

Q. Did the staff review the underlying data for every reservoir comprising the reported uncommitted reserves in Southern Louisiana?

A. No. In addition to the time limitations placed upon the staff by the necessity to complete the audit and submit the results in this proceeding, I concluded that a representative sample of the reservoirs involved would serve as an adequate basis for auditing the reported data.

Q. How did you select the sample of reservoirs that would be audited at each company's office?

A. I determined the percentage of the total reported "Available for sale" reserves which each company held as of December 31, 1969. This percentage was then applied to the total number of man-hours available for performing the audit to determine the approximate time which the auditing team would spend at each company. For example, if a company reported uncommitted reserves which equalled five percent of the total reported by

[5,197]

all producers, then I would calculate five percent of the available man-hours and instruct the auditing team that they were to spend that amount of time at that company. The auditing team was further instructed as to the selection of the reservoirs they were to check.

Q. How was this selection to be made?

A. An instruction sheet was furnished to those who would be performing the field audits. In addition to setting forth the sampling procedures, these instructions sought to insure uniformity of examination and confidentiality of the reserves held by each producer. These instructions were as follows:

"The following instruction are to be followed exactly:

1. The companies are assigned based on attached list (Appendix A)

2. You are to notify company representative 1 day prior to visit (Listed in Appendix B)

3. The company is to show you:

(a) An A and/B sheet with the total company reserve estimate sent into Auten. It should have Auten's initials and the word composited on it. In addition there will be an FPC Gas Supply Stamp on the sheets.

[5,198]

(b) A list of the reservoirs by size.

4. You will add up the reservoir volumes and check against the "Auten" sheets to make sure the numbers match.

5. Select reservoirs (1969) (onshore plus offshore) from the reservoir-by-size list on the following basis:

(a) Assuming an average of 4 hours per reservoir audit.

(b) Check Appendix A list to see how long you are to stay with the company and choose appropriate number of reservoirs to check.

(c) Select the reservoirs on the following basis:

(1) Using the distribution breakdown below select the reservoirs to be checked (the total to be checked already determined by size of company reserves) based on the distribution of the company's reservoirs in the various size categories.

[5,199]

SIZE DISTRIBUTION

0	—	5 BILLION (Small)
5	—	40 BILLION
40	—	80 BILLION
80	—	100 BILLION
100 AND OVER (Large)		

[5,200]

(2) Make the selection proportioned to the numbers of reservoirs in each group. Do all large reservoirs.

(3) Check at least one reservoir in the warranty category if the company has warranty reserves reported.

6. While the reservoirs are being checked, make a list of the company estimate and the staff estimate and when all reservoirs from the company have been checked, total these estimates and report these total staff and company estimates sampled to Mr. Lawrence R. Mangen, 386-6172 or 386-4855 in Washington, D. C. for compositing.

7. Under no circumstances will any data be taken from company offices.

8. All workpapers will be destroyed after data is reported to Mr. Mangen.

Q. How did you calculate the results of the field audits as reported to you by telephone?

A. I recorded the volume of reserves under each category which the staff auditing team reviewed at the office of each producer, first listing the estimate of these reserves by that producer and then listing the staff's estimate of the same reserves. When the audit was concluded, I composited all estimates under each category.

[5,201]

I was then able to determine the percentage of the total reported volumes we had checked and for the reserves audited, determine the variance between the estimate of the producer and that of the staff.

Q. Who actually performed the audits at the companies' offices?

A. The audit was performed by staff members expert in reserve analysis with Mr. Victor H. Zabel in charge of the field operations. Mr. Zabel's testimony on this subject describes the performance of the audit.

Q. When was the staff audited completed?

A. August 18, 1970.

Q. What were the results of the audit?

A. The staff examined approximately 33 percent of the reserves reported to be "available for sale" as of December 31, 1969. The staff estimated those reserves audited to be approximately 2 percent less than the companies had estimated.

In approximately 50 percent of the reservoirs examined, the staff and producer estimates were within + or — 10 percent, which is well within the variation usually found between independent reserve estimates. An addi-

tional 27 percent for a total of 77 percent were found to be within + or — 20 percent which is still

[5,202]

not unreasonable. The remaining staff estimates which varied more than 20 percent from the producer estimates were extremely small reservoirs and accounted for only 0.01 percent of the total volume of reserves examined.

Q. What about the other reserve categories?

A. Of course, we were primarily interested in the above category. However, the staff also examined 1 percent of the "Warranty" reserves with a difference between staff and company of about 5 percent of those checked.

In those cases where there was a significant difference between 1968 and 1969 reserves, 1968 reserves were examined also, if time permitted. Less than 1 percent of these reserves were examined with a difference of about 20 percent on those reserves checked.

Q. What check was made of those companies which filed a completed questionnaire with Arthur Young & Co. but reported they had no uncommitted reserves?

A. The staff searched the records of United States Geological Survey and Louisiana Department of Conservation well data collected by the Federal Power Commission for all companies which had filed reports with those agencies of discovery gas wells completed since 1960. The purpose of this search was to determine if any company which had not reported any uncommitted

[5,203]

reserves had completed a discovery gas well in Southern Louisiana in the past ten years.

This list was then cross-checked against reports and documents of the Louisiana Department of Conservation to determine the present status of these discovery gas wells.

Q. What was the result of this investigation?

A. We were unable to find any discovery wells for which the gas was neither committed nor covered by the uncommitted reserves questionnaires filed with Arthur Young & Co. In other words, our search did not turn up any uncommitted gas reserves which were not reported on the questionnaires.

Q. What is your opinion of the staff audit?

A. The staff spent 99 man-days and over $3,300 auditing reserves and 18 man-days and $200 investigating the companies which did not report any reserves on their questionnaire for a total of 117 man-days and over $3,500. This does not include any estimate of salaries spent. In my opinion the staff audit was fully adequate and confirmed that the volumes reported by the producers pursuant to the questionnaire were reasonably estimated and provide a reliable measure of the volumes of gas available for sale in the Southern Louisiana area as of December 31, 1969.

[5,204]

Q. Does this complete your testimony?

A. Yes.

* * * *

[5,446]

Q. As I understand it, the questionnaires, the purpose of the questionnaires was for the companies to report uncommitted proved gas reserves. Is that correct?

A. That's correct.

[5,450]

Testimony of Lawrence R. Mangen

Q. Now, did you have any procedure, did the staff have any procedure whereby it could check to determine whether or not companies had not reported uncommitted proved gas reserves?

MR. REBMAN: Mr. Examiner, just still by way of clarification, whether counsel is asking anything different than the question that was posed by the witness' own counsel on page twelve, transcript 5202. It sounds pretty much like the same thing to me.

MR. MILLER: No, this is different for this reason: As I understand the question on page twelve, that is directed only to companies who reported no uncommitted gas reserves. I am speaking of companies—

PRESIDING EXAMINER: Is there any way that you could check whether a company had reported all its uncommitted proved reserves?

THE WITNESS: The only way that we could have done it was to perform the same kind of audit that we performed for the companies that reported none.

PRESIDING EXAMINER: Well, did you do that?

THE WITNESS: No.

PRESIDING EXAMINER: Go ahead.

* * * *

[5,450]

offices of the USGS, and as a precautionary measure we simply want to get clearance before we do it. That is all we are saying.

PRESIDING EXAMINER: Are you trying to save the people who want it the price of getting it from USGS, is that the idea?

MR. MATTINGLY: No, sir, we will make it available free of charge. We just want clearance from USGS. We don't want to put everyone to the expense of going

to USGS to get this data. We are wiling to make it available.

MR. MILLER: In other words—

PRESIDING EXAMINER: All right.

I think it is clear enough at this point, Mr. Miller. Let's go ahead.

MR. MILLER: All I am trying to determine, your Honor, is whether we are going to have this information, and it appears that we are once they get clearance. Is that correct?

MR. MATTINGLY: That is the gist of it, counsel.

MR. MILLER: Thank you.

BY MR. MILLER:

Q. Was any separate determination made by the FPC, its staff or any other agency as to the validity of the reports filed as to the discovery wells completed since 1960?

A. No.

Q. How many questionnaire responses did not report any uncommitted reserves?

• • • •

[5,472]

TESTIMONY OF VICTOR H. ZABEL

MR. MATTINGLY: Mr. Zabel.

Whereupon,

VICTOR H. ZABEL

was recalled as a witness, and, having been previously duly sworn, was examined and testified further as follows:

MR. MATTINGLY: Mr. Examiner, you will remember that when Mr. Zabel was on the stand for his prior appearance, two pages of statistical data were introduced into the record at pages 5363 and 5364 of the transcript, at which time counsel proposed to ask questions of the witness based on that data. And based on Your Honor's ruling at 5370, it was agreed that over the time in the interim, the witness would have an opportunity to review this data and would respond to any further questions based upon such data at the present time. And in respect to that, I would now like to ask the witness certain additional direct testimony concerning that data that was copied into the record.

DIRECT EXAMINATION

BY MR. MATTINGLY:

Q. Mr. Zabel, would you please refer to pages 5363 and 5364 of the transcript.

Have you had a chance to review that data?

A. Yes.

Q. Now, referring specifically to page 5363, are AGA reserves in the categories new fields and new reservoirs as

shown in Column 2 comparable to the Form 15 reserves in the category new supply additions as shown in Column 3?

A. No, they are not. The AGA defines new discoveries in part as follows: "Discoveries are defined as proved reserves in newly discovered fields and newly discovered reservoirs in old fields. New discoveries seldom are delineated or fully developed during the year of discovery. Therefore, the year end reserve estimates generally represent only a part of the reserves that ultimately will be assigned".

New supply additions from Form 15 represent a composite of sources of supply reported for the first time in the individual pipeline company FPC Form 15 reports. These new sources are generally new fields reported for the first time in any Form 15. However, they may be also previously undedicated reserves in a field which is already being reported in Form 15 by another pipeline company. This category may also include reporting by a company for the first time of a dedication of residue gas from a gas processing plant. Therefore, new supply additions differ from AGA new discoveries for at least two reasons:

First, the AGA reports discoveries in the year the discoveries are made. On the other hand, new supply additions represent reserves which are reported in a company's Form 15 for the first time. The reporting of new reserves in the Form 15 may occur a considerable time after the discoveries are

[5,474]

reported by the AGA, and the reserves may be greatly increased by revisions and extensions by the time such reserves first appear in the Form 15.

Q. Can you give us an example of such a situation?

A. Yes. Assume the following: First, that a field was discovered in 1962 and the reserves reported by the AGA in 1962. Second, that extensions and revisions were added during the years 1963 and 1964, and were reported as such by the AGA. Third, that a pipeline contracted for the reserves in this field in 1965 and received its certificate of public convenience and necessity from the FPC in 1966. When the pipeline reported these reserves for the first time in its 1966 Form 15 report, it would show the total volume of proved reserves in the field, including all extensions and revisions. This entire volume would be considered new supply additions as that term is used in my testimony, and as shown at Column 3 of the transcript page 5363. Therefore, it is clear that new fields and new reservoirs as reported by the AGA and new supply additions as reported in the Form 15 represent essentially different measures of reserves.

Q. In your opinion, is there any basis for comparison between Column 2 and Column 3 of transcript 5363?

A. None whatsoever.

MR. MATTINGLY: Mr. Examiner, on the basis of the preceding testimony, I move to strike the material appearing at pages 5363 and 5364 of the transcript.

* * * *

[5,480]

BY MR. MATTINGLY:

Q. Mr. Zabel, what is the definition of proved reserves as set forth—are you aware of that definition as used in the Commission's order?

A. Yes.

Q. What is the source of that definition?

A. This is the definition used by the AGA Committee on Natural Gas Reserves.

Q. Does that definition, in your opinion, require the reporting of proved gas reserves which are discovered by the drilling of a so-called expendable well or expendable hole?

A. Yes. Reporting of uncommitted proved reserves is required irrespective of the status of the wells.

Q. What is the definition of an expendable well or expendable hole?

A. American Petroleum Institute in its Technical Report No. 1, Standard Definitions for Petroleum Statistics, at page 25, includes expendable holes in its definition of stratographic tests. Its definition reads as follows: A stratographic test is a drilling effort, geologically directed, to obtain information pertaining to a specific geological condition that might lead toward the discovery of an accumulation of hydrocarbons. Such wells are customarily drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of

expendable holes related to hydrocarbon exploration".

Simply stated, expendable wells are wells which are drilled to test underground structures and which are not designed for future re-entry and production.

Q. As a result of your audit, were you able to determine whether proved reserves underlying expendable wells were in fact reported?

A. Yes, such reserves were reported.

Q. Explain how you determined this.

A. This was determined by reference to the mechanical condition of the wells involved as shown in the reporting company's well files or records.

Q. What do you mean by mechanical condition?

A. The wells in question, the so-called expendable wells, were not equipped for production with such items as packers, tubing, valves, etc. Reports were also available showing the amount of cement used to plug the well. Furthermore, in most, if not all, of the cases these wells were cut off at the mud line.

Q. Did you audit any gas reserve estimates underlying such wells?

A. Yes. Reservoirs underlying expendable wells were analyzed to the extent that they were included in the overall sample. To the best of my recollection, reservoirs of this type comprised approximately 10 to 20 percent of all reservoirs

audited.

Q. Were you able to determine as a result of your audit whether the reserves underlying expendable wells were evaluated or reported differently than the reserves underlying produceable wells?

A. Our audit revealed that the reporting companies evaluated and reported the reserves in reservoirs underlying expendable wells in the same manner as they evaluated and reported reserves in reservoirs underlying any other type of well.

Q. Were you able to determine as the result of your audit whether uncommitted proved reserves associated with temporarily abandoned wells were reported?

A. Yes. The audit revealed that uncommitted proved reserves underlying temporarily abandoned wells were reported.

Q. How were you able to determine this?

A. Again by reference to the actual status of the well as shown by company records.

MR. MATTINGLY: That concludes the further direct, Mr. Examiner.

* * * *

[5,925]

TESTIMONY OF CHARLES A. LARSON

Q. Are you the same Charles A. Larson who testified at transcript pages 2008 to 2026 (Volume No. 14) and 5126 to 5180 (Volume No. 39)?

A. Yes.

Q. What will be the general scope of your additional testimony?

A. My testimony will deal with unit costs of flowing gas-well gas production for the Southern Louisiana Area for the years 1960, 1962 and 1969.

Q. What are the general cost elements that enter into the unit cost of gas-well gas production?

A. The cost elements are exploration and development costs, production costs, the cost of gathering gas, regulatory expenses and the Louisiana production taxes where applicable.

Q. What is the source of your basic data for determining exploration and development cost and production cost?

A. The source of the data is the various questionnaire responses for the years 1960, 1962 and 1969, respectively. Data for the year 1960 were collected from

[5,926]

the Respondents for the purpose of AR61-2 for both the Southern Louisiana Area and the Continental United States. These data are in the record in this proceeding. Data for the year 1962 were collected for both the Southern Louisiana Area and the Continental United States in the Staff's "All Areas Questionnaire". The Continental United States data for the year 1969 were collected

pursuant to questionnaires in this proceeding and are for the offshore area as well as for onshore Southern Louisiana and for the Continental United States.

* * * *

[5,927]

Q. Briefly explain Exhibit 51.

A. Exhibit 51 shows the basic cost and volume data as taken from the questionnaire responses for the exploration and development function which data are required in order to determine the cost of gas for the years 1960, 1962 and 1969 using Opinion 546 methods. Also, because the exploration and development costs reported for the year 1969 do not match that year's production volumes, Exhibit 51 shows the adjustments made to costs and to volumes in order to derive a more representative unit cost for the exploration and development function using Opinion 546 methods. The costs and volumes shown in Exhibit 51 are for the Continental United States.

Q. Briefly explain Exhibit 52.

A. Exhibit 52, which is a one-page schedule, shows the range of unit exploration and development costs for Continental United States using Opinion 546 methods and employing various economic factors to allocate the joint exploration and development costs for the years 1960, 1962 and 1969. The results range from 3.7 cents per Mcf to 13.0 cents per Mcf depending on the year

[5,928]

and economic factor chosen.

Q. Briefly explain what is in Exhibit 53.

A. Exhibit 53 shows the basic data as taken from the questionnaire responses for the production cost function

for the Southern Louisiana Area for the years 1960, 1962 and 1969 using Opinion 546 methods. Similar data for other years are not available. Additionally, Exhibit 53 shows the basic cost and volume data for Continental United States for the gas only and oil only lease classes, the unit production costs for these lease classes and the resultant relative cost ratios which are used to allocate the joint production costs.

Q. Briefly, explain what is in Exhibit 54.

A. Exhibit 54 shows the unit production costs for the Southern Louisiana Area for the years 1960, 1962 and 1969 employing various relative cost ratios to allocate the joint production costs. In this one-page exhibit the unit production costs are shown for a number of modifications to the cost allocation method used by the Commission in Opinion 546. These unit production costs range from 11.0 to 16.9 cents per Mcf

[5,929]

depending on the year and cost allocation modification selected.

Q. Briefly explain Exhibit 55.

A. Exhibit 55 shows some sample calculations. The cost allocation results shown in Exhibits 52 and 54 were calculated by a computer program. These sample calculations illustrate the method employed. The Commission's Opinion 546 method of allocation of Continental United States exploration and development cost is shown on Schedule 1 employing an economic factor of 2.0. Likewise, the Commission's Opinion 546 method of allocating production costs is shown on Schedule 2. Calculation of unit production costs using an economic factor of 2.0 is shown on Schedule 3.

Q. Please explain briefly what is in Exhibit 56.

[5,929]

Testimony of Charles A. Larson

A. Exhibit 56 shows the high range and low range of costs for the years 1960, 1962 and 1969. The low range of costs is that resulting from using the allocation methods employed by the Commission in Opinion 546. The high range of costs is represented by using an economic factor of 1 to allocate joint costs of exploration and development and of production.

[5,930]

Additionally, this one-page exhibit shows the results for the same years when an economic factor of 2.34 is used to allocate costs for both the exploration and the production functions.

Q. What are the results of those three cost allocations?

A. The results by years are shown below:

	Unit Cost of Flowing Gas-Well Gas Including Production Taxes (Cents Per Mcf)		
Allocation Factor	1960	1962	1969
Opinion 546 Factors	18.3¢	19.8¢	20.7¢
Economic Factor = 2.34	22.2¢	23.7¢	24.2¢
Economic Factor = 1	27.6¢	28.8¢	30.2¢

Q. Please explain, mathematically, the procedures you followed in preparing your cost studies.

A. Computer programs were developed to allocate the joint costs. For exploration costs, the computer program can be run employing various economic factors for oil as compared with gas. For production costs, the computer program can be run employing various relative cost ratios for (1) production expenses; (2) depreciation, depletion and amortization; and (3) return on investment. Employing the basic cost and volume data I

[5,931]

derived the unit costs by means of these computer programs.

Q. Can the computer programs be used to allocate the costs in the same manner as did the Commission in Opinion 546?

A. Yes, the same methods can be followed to allocate the exploration and production costs. However, since it appears desirable to show modifications to the Opinion 546 methods, the allocation methods were computerized in order to show the impact of possible modifications of the Commission's methods.

Q. You said above that the general cost elements involved in determining the cost of gas-well gas are the cost of exploration and development, the cost of production, the gathering costs, regulatory expenses, and Louisiana production tax where applicable. Turning first to the gathering costs, how did you determine this cost element for the years 1960, 1962 and 1969?

A. I used the Opinion 546 costs for the year 1960, the stipulated costs for the year 1969, the 1969 costs for the year 1962.

Q. Why did you use the 1969 gathering costs for the year 1962?

[5,932]

A. Since it is a minor cost function for which adequate data are not available, I chose to use the same gathering costs for each of the years 1960, 1962, and 1969.

Q. How did you determine the regulatory expenses?

A. I used the opinion 546 costs for the year 1960, the stipulated costs for the year 1969, and the 1969 costs

for the year 1962. These costs amount to only 0.15 cents per Mcf which I rounded to 0.2 cents per Mcf.

Q. How did you determine the production taxes?

A. I used the statutory rate of 2.3 cents per Mcf.

Q. As to the cost element for exploration and dedevolpment, please explain what costs are included in this category.

A. For the most part, exploration and development (E & D) costs are dry hole costs, lease rentals, the cost of cancelled and surrendered leases, geological and geophysical expenses, and return on the investment in equipment used in E & D operations. A portion of area, district, division and field administrative and general expenses and related return on investment are also allocated to the E & D function. The basic data for the E & D Function are shown in Exhibit 51.

Q. In computing a cost of service for flowing gas-well gas

using Opinion 546 methods, why is there a need to allocate exploration and development costs?

A. There is no way of accounting for the exploration and development costs for gas separately. That is not to say that companies have never been able to segregate a portion of their exploration and development costs between gas reservoirs on the one hand and oil reservoirs on the other hand. However, even if the cost of finding gas reservoirs were known there would still remain the problem of allocating those costs between gas and condensate.

Q. Have you attempted to assign directly the cost of finding gas reservoirs in your cost allocation methods?

A. No. There is some information available which could be used in assigning some of the costs directly to

oil or gas reservoirs, but I have endeavored here to stay with basic Opinion 546 methods. Accordingly, I used the composite Continental United States costs which I allocated to gas employing the modified Btu method as did the Commission in Opinion 546.

Q. Are there many allocation methods which could be used to allocate the joint costs of finding and producing oil and gas?

[5,934]

A. Yes, there are literally hundreds of methods, or permutations of methods, which could be used to allocate the joint costs in lieu of the modified Btu method and the relative cost method.

Q. Please explain the modified Btu method which was used by the Commission in Opinion 546.

A. The modified Btu method of allocation was used to allocate costs which were incurred jointly. For example, when an oil reservoir is discovered, some natural gas is associated with the oil in the reservoir. On the other hand, when a gas reservoir is discovered, some condensate is usually a part of the gas stream from the reservoir. Thus, oil and gas, and condensate and gas, are explored for jointly. Therefore, before the cost of gas can be determined there must be an allocation of the joint costs.

The modified Btu method allocates exploration and development costs to gas and to liquids (oil and condensate) in proportion to the weighted Btu's produced during the test year. In Opinion 546 the Commission used an economic factor of 3.5 to weight the liquid Btu's. The result is that a Btu of oil or condensate is allocated 3.5 times as

[5,935]

* * * *

[5,935]

Testimony of Charles A. Larson

Q. Now, having explained the general method in Opinion 546,

[5,936]

tell us what Exhibit 52 shows.

A. Exhibit 52 summarizes the exploration and development cost of service element for the years 1960, 1962 and 1969, computed (1) according to Opinion 546 methods using the 3.5 to 1 value relationship between oil and gas and (2) using alternative, more appropriate, value relationships.

Q. In your Exhibit 52 you have shown cost determinations for 1969 under three different methods shown in Columns C, D and E. Please explain these different methods.

A. Column C of this schedule, which I do not recommend for the reasons stated below, shows the calculation of unit E & D costs on the basis of actual E & D costs and production volumes as experienced during the year 1969. Columns D and E show alternative and more appropriate computations reflecting adjustments called for because the static exploratory effort during the 1960's had not kept pace with increases in the production so that 1969 actual exploratory costs and production are completely out of balance. This divergence is clearly evident from Schedule 5 of Exhibit 51 which shows that the exploration and development costs have remained essentially constant

[5,937]

over the last decade while production of hydrocarbons in 1969 increased by 46 per cent over 1960 production.

Q. I will ask you to explain the reasons for this alternative computation in detail later, but now tell us what Column D shows.

A. Column D shows a cost-of-service for exploration and development in which actual 1969 E & D costs are brought into balance with actual 1969 production by adjusting the actual E & D costs upward.

Q. How did you make this adjustment to E & D costs?

A. I determined from the AGA and Bureau of Mines reports that production of oil and gas Btu's in the Continental United States was 46 per cent greater in 1969 than it was in 1960, and I adjusted the 1969 cost on the basis of this increase in production. The details of this adjustment are presented in Schedule 5 of Exhibit 51.

Q. I will ask you to explain the applicable Schedules in Exhibit 51 later, but now tell us what Column E of Exhibit 52 shows.

A. In this column I have made a comparable cost of service based on the use of alternative production volumes for 1969 in conjunction with actual E & D costs for that year.

[5,938]

Q. Please explain this alternative computation.

A. This alternative computation is based on Schedule 4 of Exhibit 51. In this calculation I adjusted the 1969 production volumes so as to maintain the same findings to production ratio with which the Commission was apparently satisfied in its Opinion 546. I relied on the method used by the Commission in Opinion 546 to calculate productivity (findings of gas per foot drilled). Similarly, I computed the productivity of crude oil, natural gas liquids, associated gas and non-associated gas for the period 1947-1961. I then calculated the findings to production ratio per Opinion 546 by multiplying the actual footage drilled in the various well classifications by the respective productivity and dividing that product

by the actual production volumes, each for the period 1961-1966.

Next, I calculated findings for 1969 by multiplying the footage drilled in 1969 by the productivity. Production from each of the four production classifications (crude oil, natural gas liquids, associated gas and non-associated gas) was then calculated for 1969 which would result in

[5,939]

a findings to production ratio consistent with that of the 1961-1966 period.

Finally, I adjusted 1969 production volumes for each of the well classifications on the basis of the factors computed for each of the four production classifications computed on Sheet 3. (Sheet 1, Schedule 4, Exhibit 51). In this manner I achieved a more representative matching of 1969 volumes and costs.

Q. I will ask you to explain the details of Schedule 4 of Exhibit 51 later, and will now ask you why in your opinion it is necessary to use the alternative cost determinations for 1969 shown in Columns D and E of Exhibit 52.

A. The demand for natural gas has increased with population growth, more intensive utilization, an increased inelasticity of demand and because of air pollution problems. Annual production of natural gas rose steadily during the 1960's. While the demand for natural gas and its production was steadily increasing the exploratory effort was remaining static. Apparently the gas producing industry was devoting its efforts only to exploration and development of the better lower cost prospects because it did not have

[5,940]

the economic incentives to drill faster. Findings of natural gas did not keep pace with production as is evident from the AGA statistics on proven reserves. By 1969, findings were only about 40 per cent of production. In the face of rising demand and production, the industry cannot keep going on the basis of low and static exploratory expenditures. Exploration must be at a rate materially higher than it was in 1969. Mr. Winger has made this abundantly clear in this testimony.

In my opinion under these circumstances, the only way that a realistic cost of gas can be determined is to adjust either the exploratory expenditures to match the 1969 actual production or to adjust the production to match 1969 expenditures. The higher 1969 production warrants a higher exploratory effort and the cost of service must encompass this fact. If the 1969 cost of service includes only the 1969 exploratory effort averaged over the higher 1969 production volumes, a false picture is shown and the results are misleading. The gas industry is using up its inventory without plowing back costs sufficient to replace the gas taken. From a public interest point of view, the

[5,941]

cost of service must place these two all important factors—costs and production volumes—into balance.

Under the producers' usual accounting procedures, the exploration and development costs incurred in a year are charged to current production rather than related to the reserves discovered during such year. Thus, test year exploration and development costs are divided by test year production to obtain a unit cost which is a proxy for unit exploration and development cost applicable to gas

which is now flowing but which was discovered in prior years.

This unit cost has meaning only if the finding to production ratio, and thus the annual production and the annual expenditures, maintain a reasonable constant relationship from year to year.

Current production is in no way affected by current E & D costs. When production and E & D costs are out of balance, as they were in 1969, some adjustment of one or the other is clearly needed if the calculation of a proxy type

[5,942]

exploration and development unit cost is to have any meaning. The relatively smaller E & D costs that the producers are now incurring will at some time in the future result in decreased production.

Q. Now, Mr. Larson, referring to the detailed explanation of the alternative cost determinations for 1969, explain the first three schedules of Exhibit 51.

A. Schedule 1 shows a breakdown of the Continental United States E & D expenses for the years 1960, 1962 and 1969. Schedule 2 shows a breakdown of the E & D rate base for the same years. Schedule 3 shows the Continental United States production of gas and oil by lease classifications for the same years, and the Btu content of each of the lease products.

Q. What is shown on Schedules 4 and 5 of Exhibit 51?

A. Schedule 4 shows an adjustment to 1969 production volumes to more properly match the E & D costs with production for that year. Schedule 5 shows an alternative adjustment to 1969 exploration and development costs.

* * * *

[5,943]

E & D costs with production volumes. Column A shows the actual 1969 production volumes by lease classification Column B shows the adjustment factor as derived on Sheet 3 of this schedule. Column C shows the 1969 adjusted production volumes which were derived by multiplying Column A times Column B.

Q. What is shown on Sheet 2 of Schedule 5 of Exhibit 51?

A. Sheet 2 shows the findings of natural gas, natural gas liquids and crude oil per foot of successful wells drilled during the period 1947-1961. The footage of successful gas wells and successful oil wells is shown in Columns A and B, respectively. The annual findings of non-associated gas, natural gas liquids, crude oil and associated gas, respectively, are shown in Columns C, D, E and F. The average findings per foot drilled for each of these four product classifications are shown on Line 17. These findings per foot drilled (productivity) for the period 1947-1961 are:

Non-associated Gas	587 Mcf/ft.
Natural Gas Liquids	29 bbl/ft.
Crude Oil	31 bbl/ft.
Associated Gas	53 Mcf/ft.

[5,944]

Q. Why did you select the period 1947-1961 to determine productivity?

A. This is the period used by the Commission in Opinion 546 for the purpose of computing the cost of new non-associated gas.

Q. What is shown on Sheet 3 of Schedule 4 of Exhibit 51?

[5,944]

Testimony of Charles A. Larson

A. I show on Sheet 3 the derivation of the factors used on Sheet 1 to adjust the 1969 production volumes. Factors were derived to adjust: (1) non-associated gas; (2) associated gas; (3) natural gas liquids; and (4) crude oil. On lines 1-6, I show the successful footage for oil and gas wells, and and the production and calculated findings of the four production classifications, for each of the years 1961-1966. The findings for each of the years for each product were imputed by multiplying the footage drilled during that year by the productivity as computed on Sheet 2 of this schedule. Findings of non-associated gas and natural gas liquids were computed for each year by multiplying the respective productivity by the annual footage of successful gas well drilling. Findings of associated gas and crude oil were computed by multiplying the respective productivity by the annual footage of

[5,945]

successful oil well drilling. The total of these imputed findings for the period 1961-1966 when divided by the total production for the same period results in the findings to production ratios shown on Line 8 for the respective products.

Q. In making the adjustments, what is the significance of this findings to production ratio?

A. The findings to production ratio for non-associated gas is the one that the Commission used in Opinion 546 to make the adjustment for exploration in excess of production in the new gas cost of service. I computed the findings to production ratio for the other products by the very same method and for the very same period. The Commission has used the data resulting in these findings to production ratios in its Opinion 546 and has raised no problem with including the industry expenditures

associated with the effort to produce such ratios in the cost of service.

I have therefore concluded that, since the effort in 1969 is approximately the same as in 1960, a representative unit cost can be obtained by adjusting the 1969 production

[5,946]

volumes so as to maintain the same findings to production ratio as existed when the Commission issued its Opinion 546 and as presumably existed at the time that much of the gas now flowing was found.

Q. Please continue your explanation of Schedule A, Sheet 3 of Exhibit 51 and explain how you computed the findings for 1969.

A. I show on line 9 the successful footage, the production—and the calculated findings for non-associated gas, associated gas, natural gas, liquid and crude oil for 1969. The findings of non-associated gas and natural gas liquids were calculated by multiplying the successful gas well footage drilled in 1969 by the average productivity for the years 1947-1961. The findings of associated gas and crude oil were calculated by multiplying the successful oil well footage drilled in 1969 by the average productivity for the years 1947-1961.

Q. Why did you calculate the 1969 findings rather than rely on findings as reported by the AGA?

A. What I attempted to do here was to determine what production would have been consistent with the expenditures (effort) made. The findings used should therefore be

[5,947]

consistent with this effort and not subject to the normal variations in productivity from year to year. The Com-

mission has recognized the need to compute productivity on an average basis and I used the same period that the Commission used for the purpose of normalizing 1969 findings.

Q. What is shown on line 10?

A. Line 10 shows the production that results in a findings to production ratio consistent with the one shown on line 8.

Q. What is shown on line 11?

A. Line 11 shows the ratio of imputed production in 1969 to actual production. This is the adjustment factor shown in Column B of Sheet 1 of Schedule 4 of Exhibit 51.

Q. Please show the magnitude of this adjustment.

A. Continental United States production in 1969 of the four production classifications was adjusted as shown below:

	Actual	Imputed	Percent
Non-associated Gas—MMcf	16,059	9,299	57.9
Natural Gas Liquid—Mbbls	735,962	429,472	58.4
Associated Gas—MMMcf	4,777	2,900	60.7
Crude Oil—Mbbls	3,195,291	1,959,678	61.3

Q. What do you show on Schedule 5 of Exhibit 51?

[5,948]

A. Schedule 5 of Exhibit 51 shows the calculation for 1969 based on an alternative adjustment of exploration and development costs.

Q. Please explain Sheet 1 of Schedule 5 of Exhibit 51.

A. Lines 1-10 of Sheet 1 show the annual industry exploration and development expenses for the years 1960-1969. These data show that expenditures on exploration and development activities have been rather constant

throughout this 10-year period except for modest increases in 1968 and 1969. Mr. Winger attributes this increase to the increased cost of lease acquisitions (TR 4879). The industry exploration effort in 1969 was therefore approximately the same as it was in 1960.

I, therefore, show on line 11 an adjustment of the 1960 Continental United States industry-wide exploration and development expenses of $1,475 million upward by 46 per cent to $2,154 million. The 46 per cent factor was developed on Sheet 2 of Schedule 5 and represents the growth in Btu's of hydrocarbon production over the period 1960-1969.

[5,949]

Line 12 shows that Respondents' exploration and development expenditure in 1969 were 52 per cent of the industry-wide exploration and development expenditures.

Line 13 shows that the Respondents' share of the industry-wide imputed exploration and development expenditures in 1969 amounted to $1,120 million, on the basis of the 52 per cent factor.

Line 14 shows other expenses of $572 million which are not included in line 13.

Line 15 shows the adjusted Continental United States expenditures of the Respondents in 1969 to be $1,692 million.

Q. Please explain Sheet 2 of Schedule 5 of Exhibit 51.

A. This schedule shows the development of the factor used on Sheet 1 to adjust exploration and development costs. Volumetric production for the years 1960 through 1969 for crude oil, natural gas liquids and natural gas are shown in Columns A, B and C. In Columns D, E and F, the respective production volumes shown in Columns A, B and C

are converted to Btu's in order to be able to combine the total production in Column G employing a common denominator, namely, the Btu's produced. On line 11 the 1969 production of Btu's is shown to be 46 per cent greater than the 1960 production of Btu's.

Q. Now Mr. Larson, having explained the alternative cost determinations for 1969 shown in Columns D and E of Exhibit 52, please refer to line 1 of Exhibit 52, and tell us what that shows?

A. I have shown the calculation of unit E & D costs using an economic factor 3.5. I show this calculation at 3.5 because this is the factor that the Commission used in Opinion 546, even though there are a number of problems with this factor.

Q. What are some of the problems that you have with the Commission's 3.5 economic factor?

A. First, the Commission arrived at this factor on the basis of an unregulated market price for oil *vis-a-vis* a regulated price for gas. The resulting ratio or economic factor is inaccurate considering the higher price of gas allowed in the Southern Louisiana Area—20 cents per Mcf instead of 16.5 cents per Mcf for the Permian Basin

Area. A price of 20 cents might well be used in lieu of 16.5 cents. Likewise, calculating the economic factor on the basis of the 26-cent ceiling price on new gas as proposed in the settlement filed by UDC, the economic factor would be 2.34 rather than 3.5 as used by the Comission in Opinion 546.

Again, evidence presented by Mr. Ogden in Exhibit 57 (WJO-1) indicates that a factor of 2 would not be too low.

Finally, this factor cannot remain constant because of changing value relationships.

Q. Now, turning to Exhibit 52 again, what do you show on line 2?

A. This shows the exploration and development costs using a factor based on a 20-cent gas price in lieu of the 16.5-cent gas price employed by the Commission in Opinion 546. This produces an economic factor or value relationship of 2.92 in lieu of 3.5. As shown, the exploration and development cost for gas is increased .6 cents by this change.

[5,952]

Q. Why did you show an economic factor of 2.34 on line 3 of of Exhibit 52 as a possible modification of Opinion 546 methods?

A. This is the value relationship using a ceiling price of 26 cents, the ceiling price on new gas agreed to in the settlement filed by UDC.

Q. Why did you show the results using an economic factor of 2.0 on line 4 of Exhibit 52 as a possible modification of Opinion 546 methods?

A. This is to show the effect of assuming the value of gas consistent with the range of the new gas cost presented by Mr. Ogden and centered around the 27.58¢/Mcf figure shown in Schedule 1 of Exhibit 57 (WJO-1).

Q. Why did you show the results using an economic factor of 1 on line 5 of Exhibit 52 as a possible modification of Opinion 546 methods?

A. This shows the result if one assumes that gas has a value in all respects equal to that of oil and that gas must bear a full share of allocated costs.

Q. Considering the changes that have taken place since 1960, what method of cost allocation do you recommend to allocate E & D costs?

A. First, for 1969, I recommend the use of Column E to portray a balanced cost of service for that year.

Secondly, I recommend that for each of the years 1960, 1962 and 1969, the economic factor of 3.5 is unrealistic and that a lower one presents a much sounder approach to the allocation of joint costs between gas and oil. The selection between the several alternatives which I have presented would depend upon the Commission's conclusion as to the proper value relationship in the light of all considerations applicable to those years.

Q. Please summarize what is shown in Exhibit 52.

A. Exhibit 52 shows the results of computing exploration and development costs for gas-well gas using various economic factors for the years 1960, 1962 and 1969. This schedule shows that such costs range from a low of approximately 4 cents per Mcf to a high of approximately 13 cents per Mcf. Thus, the high range is more than triple the low point of the range.

Q. Turning next to the cost element for production, please

explain what costs are included in this category.

A. The production cost element is comprised of (1) the return on investment in lease and well equipment, leaseholds and intangible drilling costs, (2) depreciation, depletion and amortization of those investments, and (3) operating expenses. A portion of area, district, division and field administrative and general expenses and related return on investment are also allocated to the production function.

Q. Turning now to the allocation of production costs, are the basic data for the production function for the

years 1960, 1962, and 1969 shown in one of your exhibits?

A. Yes. Production basic data are shown in Exhibit 53.

Q. Please explain that exhibit.

A. The cost and volume inputs for the production cost of service for the Southern Louisiana Area are shown on Schedule 1 by lease class for the years 1960, 1962 and 1969. Schedule 2 shows the derivation of the production rate base by lease class for the same years.

Q. What is shown on Schedule 3?

A. Schedule 3 shows the relative cost ratios which were used to allocate joint production costs.

[5,955]

Q. What is shown on Schedule 4?

A. Schedule 4 shows the unit costs which are used to derive the relative cost ratios shown on Schedule 3.

Q. What does Schedule 5 show?

A. The basic cost and volume data used to derive the unit costs shown on Schedule 4 are shown on Schedule 5.

Q. What method was used by the Comission in Opinion 546 to allocate the joint production costs?

A. In Opinion 546 the Commission used the relative cost method to allocate joint production costs.

Q. Please describe the relative cost method.

A. The relative cost method purports to allocate the joint product costs in proportion to the ratio of the cost of producing oil in the absence of gas (oil leg) and the cost of producing gas in the absence of oil (gas leg).

Q. Can the relative cost method of allocation be used to determine precisely the proportion of joint costs that should be allocated to gas on one hand and oil on the other?

A. No, and I know of no method which can be so used. The method is a helpful tool, but we must recognize that there are many different applications of the relative

[5,956]

cost method. In its application, unrealistic results can be obtained if we ignore relevant facts applicable to the particular situation.

Q. How did the Commission in Opinion 546 determine the oil leg and the gas leg?

A. The oil leg used by the Commission was the unit cost of producing oil on oil-only leases in Continental United States. The gas leg used by the Commission was the unit of cost of producing gas on gas-only leases in Continental United States.

Q. Why did the Commission employ Continental United States (national) legs to allocate Southern Louisiana Area production costs?

A. The Commission concluded that the Southern Louisiana Area legs were not representative.

Q. Would the use of Southern Louisiana Area oil only and gas only legs to allocate area costs have resulted in a higher allocated cost of gas for the Southern Louisiana Area?

A. Yes.

Q. For which lease classes was the relative cost method used to allocate production costs in Opinion 546?

A. Only for the gas-condensate leases which had condensate

[5,957]

separated on the lease. All of the costs on the gas-only leases and gas-condensate leases with no lease separation were assigned to gas. Accordingly, no allocation of

production costs were made for these two lease classes.

Q. In determining the unit production costs for gas-well gas did the Commission in Opinion 546 include the costs and volumes associated with the gas wells on combination leases?

A. No. The Commission in Opinion 546 included only the production cost and the volume of gas from the three gas lease classifications, namely, (1) gas-only, (2) gas-condensate with no lease separation, and (3) gas-condensate with lease separation.

Q. Please continue your explanation of the relative cost method.

A. An oil leg and a gas leg are determined for three types of cost, namely, (1) operating expenses, (2) depreciation, depletion and amortization, and (3) return on rate base.

Q. Did the Commission in Opinion 546 determine six different legs?

A. Yes. Two legs—oil and gas—were determined for each

[5,958]

of the three types of costs. In other words, three relative cost ratios were employed to allocate the joint production costs on gas-condensate leases with lease separation.

Q. What kind of expenses are included in operating expenses?

A. Operating expenses include the out-of-pocket costs of lifting the oil, including pumping costs, and of producing the gas. Overhead expenses are included in operating expenses.

Q. What cost is depreciated?

A. The cost of the lease and well equipment is depreciated often on the basis of the life of the equipment.

Q. What cost is depleted?

A. The cost of the lease is depleted usually on a unit of production basis.

Q. What cost is amortized?

A. The intangible drilling costs incurred in drilling the well is amortized usually on a unit of production basis.

Q. What rate of return was used by the Commission in Opinion 546?

A. A 12 per cent rate of return was applied to the rate base.

[5,959]

Q. How was the rate base determined by the Commission in Opinion 546?

A. The Commission used the year-end net investment in lease and well equipment, leasehold cost and intangible drilling costs. Overhead net investment was included as were materials and supplies, prepayments and 1/8 of the operating expenses.

Q. Did the Commission in Opinion 546 use an oil leg to allocate costs to condensate?

A. Yes.

Q. Could the Commission have used a condensate leg to allocate condensate?

A. No. Condensate is not produced by itself. It is part of a common gas stream from a gas well or gas-condensate well.

Q. Is condensate a gas?

A. In the state that condensate is produced it is a vapor. When the pressure is reduced in a separator the condensate vapor in the gas stream liquefies and separates out.

Q. Turning now to your allocation of production costs, what is shown in Exhibit 54?

A. Exhibit 54 shows the allocated production costs of gas

[5,960]

from gas leases for the Southern Louisiana Area for the years 1960, 1962 and 1969 employing various relative cost ratios.

Q. Are there various cost allocation ratios which can be used to allocate production costs?

A. Yes. Some of these cost ratios produce a high range of costs; other ratios produce a low range of costs. The relative cost ratios used by the Commission in Opinion 546 produce a low range of costs.

Q. What are some possible modifications of the relative cost method as used by the Commission in Opinion 546?

A. Some of the possible modifications of the relative cost methods are shown on lines 2-12 of Exhibit 54. These modifications include (a) the exclusion of the Hugoton Field costs from the gas and oil legs (line 2), (b) the inclusion of shut-in leases in the relative cost legs (line 3), (c) the exclusion of shut-in wells from the legs (line 4), (d) the use of sales volumes (line 5), (e) the use of net investment legs in determining the relative cost ratio for use in allocating the return of net investment (line 6), (f) combinations of the above (lines 7, 8 and 9), and (g) the use of economic factors

[5,961]

of 3.5, 2 and 1 to allocate production costs (lines 10, 11 and 12).

Q. What is shown on line 1 of Exhibit 54?

A. Line 1 shows the production cost of gas for the years 1960, 1962 and 1969 following the method used by the Commission in Opinion 546.

Q. Please refer to Exhibit 54 and explain what is shown on line 2.

[5,961]

Testimony of Charles A. Larson

A. On line 2, I show a possible modification of the relative cost method as used by the Commission in Opinion 546. If the cost included in the gas and oil legs from the Hugoton Field were excluded, the production cost of gas for 1962 would be increased 2.4 cents per Mcf, from 12.6 cents per Mcf to 15.0 cents per Mcf. The 1969 unit cost would be increased by 0.6 cents per Mcf, from 11.5 cents per Mcf to 12.1 cents per Mcf. Data were not available to make a similar adjustment for the test year 1960.

Q. What is the reason for excluding the Hugoton Field costs from the relative cost legs?

A. The inclusion of these costs and volumes distorts the proper relationship of the oil and gas legs. The national oil and gas legs were used by the Commission in Opinion

[5,962]

546 to derive the relative cost ratio because the Southern Louisiana oil only and gas only legs were found by the Commission to be too "thin" to provide an adequate sample. But there is a serious question as to whether the national ratio is representative of Southern Louisiana. A significantly increasing share of the new drilling in the Southern Louisiana Area is to deep reservoirs at high drilling costs. In contrast, the cost of drilling the old Hugoton Field gas wells which is a large part of the national average is relatively low because of the ease of drilling onshore to shallow depths. Accordingly, there is little relationship between the two types of operations and one should not be used as a proxy for the other. In other words, the costs of drilling gas wells on the plains of Kansas is not a useful tool in determining the cost of drilling a gas well in the bayous of Southern Louisiana, or in the offshore area. If the Hugoton ex-

perience is included, it becomes a high percentage of the gas leg, and since the Hugoton cost is about the lowest in the United States, it creates a great distortion when the result is to be used to allocate costs in high cost areas such as in Southern Louisiana.

[5,963]

Q. How did you make the computation so as to exclude the Hugoton costs and volumes?

A. I will illustrate the computation using gross investment relative ratios for the year 1962. The gross investment relative cost ratio is used to allocate return on rate base which is the most significant of the three production costs, namely, (1) expenses, (2) D, D & A, and (3) return. The following table shows the basic data.

	Oil Leg	Gas Leg
Gross Investment ($ millions):		
Continental U.S.	$2,883	$1,126
Hugoton Area	515	410
Continental U.S. Excluding Hugoton Area	$2,368	$ 716
Production Volumes (millions of barrels or Mcf):		
Continental U.S.	286	1,470
Hugoton Area	87	1,009
Continental U.S. Excluding Hugoton Area	199	461

From the above table it can be calculated that Hugoton gas makes up 69 per cent (1,009÷ 1,470) of the volume in the gas leg but only 36 percent (410 ÷ 1,126) of the costs.

The legs are calculated as shown below:

Continental U.S.

Oil Leg = $12.22 per barrel (2,883 ÷ 236)
Gas Leg = $0.77 per Mcf (1,126 ÷ 1,470)
Relative Cost Ratio = 15.9 (12.22 ÷ 0.77)

Continental U.S. Excluding Hugoton Area

Oil Leg = $11.90 per barrel (2,368 ÷ 199)
Gas Leg = $1.55 per Mcf (716 ÷ 461)
Relative Cost Ratio = 7.6 (11.90 ÷ 1.50)

Excluding Hugoton area costs and volumes the oil leg *declined* from $12.22 per barrel to $11.90 per barrel whereas the gas leg *increased* from $.077 per Mcf to $1.55 per Mcf. This resulted in a decline in the relative cost ratio from 15.9 to 1 to 7.6 to 1. In other words the allocation factor was more than doubled by including the Hugoton area costs and volumes in the Continental United States legs which were used to allocate Southern Louisiana Area production costs.

Q. Please refer to Exhibit 54 and explain what is shown on line 3.

A. This calculation shows a modification of Opinion 546 to allow the shut-in leases to remain in the oil and gas legs. The Commission excluded these shut-in leases from the legs in its calculations in Opinion 546.

Q. What are the results of this modification?

A. As a result of this modification, the production costs in 1960 were increased from 11.0 cents per Mcf to 11.4 cents per Mcf or by 0.4 cents per Mcf. In 1962,

the costs were increased from 12.6 cents per Mcf to 12.8 cents per Mcf. In 1969, the costs were increased from 11.5 cents per Mcf to 11.6 cents per Mcf.

Q. Please explain the mechanics of this modification.

A. In 1960, there were a number of shut-in gas leases which were waiting for connection to a pipeline. (This is not the case today.) In 1960, the following relationships existed in regard to the net investment in shut-in leases in Continental United States.

Net Investment	Oil Leg	Gas Leg
	—($ million)—	
Total Leases	$1,508	$316
Shut-In Leases	47	73
Excluding Shut-In Leases	$1,461	$243
Production Volumes (millions of barrels or MMcf)	331	808

Based on the data above the oil leg is $4.54 (1,461 ÷ 331) and $4.40 (1,461 ÷ 331) per barrel, including and excluding the shut-in leases, respectively. The gas leg is $0.39 (316 ÷ 808) and $0.30 (243 ÷ 808) per Mcf, including and

excluding the shut-in leases, respectively. Thus, by excluding the shut-in leases from the legs the Commission in Opinion 546 increased the relative cost ratio for net investment from 18.0 (811.37 ÷ 0.63) to 21.1 (11.20 ÷ 0.53).

Q. What is the rationale for allowing the shut-in leases to remain in the legs?

A. The legs are calculations of the cost of producing oil and gas, separately. These relative costs are used to

allocate the joint production costs. The joint production costs include shut-in leases as do the single product oil and gas leases. Accordingly, the relative costs of shut-in leases in the legs are representative for purposes of allocating joint production costs.

Q. Why are leases shut-in?

A. Gas leases are frequently shut-in while waiting connection to a pipeline. Gas wells offshore may be shut-in for a long time waiting for a pipeline. On the other hand, an oil well needs only to wait for a tanker before production commences. Oil leases are frequently shut-in while waiting for secondary recovery operations to start. This, of course, occurs after substantial depletion. Nevertheless,

[5,967]

these are costs of producing oil and gas.

Q. Do you think it is reasonable to include shut-in gas leases?

A. Yes, if we are to realistically determine the gas costs in the light of today's economic condition. Leaving out shut-in leases results in an omission of costs which modifies the relative cost ratio.

Q. Are there also shut-in wells on producing leases?

A. Yes.

Q. Did the Commission in Opinion 546 exclude the shut-in wells on producing leases from the legs?

A. No, and I should point out that single oil wells on a lease are frequently shut-in, while if a gas well is shut-in, the whole lease is usually shut-in. It would be more inappropriate to exclude shut-in wells than shut-in leases. I show on line 4 that this results in an increase in cost of 0.1 cent per Mcf for the year 1969.

Q. Were shut-in well costs available for the first time for the year 1969?

A. Yes. Shut-in well costs were not available to the Commission in its Opinion 546.

Q. What are the basic data which are needed to make this

[5,968]

modification?

A. These data are shown below for Conitnental United States Gross Investment legs.

Gross Investment	Oil Leg	Gas Leg
Total Including Shut-In Leases	$3,860	$1,364
Shut-In Wells on Producing Leases	298	94
Total Producing Wells	$3,562	$1,270
Production Volumes (millions of barrels or MMcf)	279	1,768

Q. What is the impact on the Continental United States relative cost ratio for including shut-in wells in the legs?

A. The oil leg is reduced from $13.81 (3,860 ÷ 279) to 12.74 (3,562 ÷ 279) per barrel by excluding shut-in wells on producing leases from the oil leg. Similarly, the gas leg is reduced from $0.77 (1,364 ÷ 1,768) to $0.72 per Mcf (1274 ÷ 1,768). The relative cost ratio decreases from 18.8 (13.81 ÷ 0.77) to 17.8 (12.74 ÷ 0.72) by excluding shut-in wells on producing leases from the legs. In other words, by not making this modification the Commission in Opinion 546 decreased the cost it allocated to gas.

Q. What is the modification of the relative cost method

[5,969]

as used by the Commission in Opinion 546 shown on line 5 of Exhibit 54?

A. The modification is the use of sales volumes rather than gross production volumes of gas, both in the allocation of joint costs and in the gas leg. In Opinion 546 the Commission used gross production volumes for both purposes. Sales volumes represents gas which has permanently left the lease.

Q. Why is it more appropriate to use sales volumes of gas than to use gross volumes in the cost allocation method?

A. The objective of the relative cost method is to cost the gas which is sold in interstate commerce and regulated by the Federal Power Commission. In fixing pipeline rates the Commission divides the cost of service by the volumes of gas sold in order to recoup the costs.

Similarly, the gas production costs should be divided by the sales volumes in order to recoup costs.

Q. What is the impact of this modification?

A. The impact is to increase the 1960 unit production cost by .7¢ and the 1962 unit production cost by .8¢.

Q. What is the modification of the relative cost method as

[5,970]

used by the Commission in Opinion 546 shown on line 6 of Exhibit 54?

A. In opinion 546 the Commission used gross investment to derive the legs used to allocate return on net investment for the joint product leases. In this adjustment I have used net investment.

Q. What are the legs when gross and net investment are employed?

A. The legs are shown below for the net investment relative cost ratios for 1960.

	Relative cost Legs	
	Net Investment	Gross Investment
Oil Leg ($ per barrel)	$4.402	$11.173
Gas Leg ($ per Mcf)	0.301	0.529

The resultant relative cost ratios are 21.12 (11.173 ÷ 0.529) and 14.62 (4.402 ÷ 0.301) using gross and net investment legs, respectively. The result of the Commission use of gross investment legs in Opinion 546 was to decrease the cost of gas 0.6 cents per Mcf for the year 1960.

Q. Why is it more appropriate to employ net investment legs?

A. The return that is allocated is computed from the *net*

investment in production facilities. Thus, using *net* investment legs is consistent with allocating return on *net* investment. It is inconsistent to use gross investment factors to allocate net investment. Second, there is no recognition of the age of the investment. Many old oil wells are on secondary recovery with little net investment. If we use the gross investment, we allocate disproportionate costs to oil and conversely we fail to give proper recognition to the actual cost of producing gas.

Q. What costs are shown on lines 7 and 9 of Exhibit 54?

A. On line 7 is shown the production costs using the modifications shown on lines 3 and 6, namely, the shut-in lease costs in the legs and the use of net investment

legs. On line 8, the same modifications are used along with the modification shown on line 2, namely, the exclusion of the Hugoton leg costs. On line 9, the costs are shown employing the modification shown on lines 3, 5 and 6.

Q. What do you show on lines 10-12 of Exhibit 54?

A. I employ an economic factor to allocate the joint production costs as an alternative to the relative cost method. In Opinion 546 the Commission used an economic factor of 3.5 to allocate the joint *exploration and development* costs.

[5,972]

On line 10, I have used the same economic factor to allocate the joint *production* costs.

Q. If, instead of using the relative cost method in Opinion 546, the Commission had used the same economic factor to allocate *production* costs it used to allocate exploration and development costs, what would have been the result?

A. If the Commission had used the same economic factor of 3.5 in 1960 to allocate production costs, the production cost of gas would have been increased by 1.4 cents per Mcf, from 11.0 cents to 12.4 cents per Mcf. In 1962, the production costs would have increased by 1.1 cents per Mcf, from 12.6 to 13.7 cents per Mcf. And in 1969, the production costs would have increased by 0.6 cents per Mcf, from 11.5 to 12.1 cents per Mcf.

Q. Has any party recommended employing an economic factor to allocate joint production costs?

A. Yes. In Docket No. AR61-2, The California Company, recommended (Vol. 12, Part 6, Tr. 3153) that the Commission employ an economic factor of 2 to allocate production costs.

Q. What is the impact of using an economic factor of 2.34 to allocate production costs?

A. The impact is shown on line 11 of Exhibit 54. Had the

[5,973]

Commission in Opinion 546 used an economic factor of 2.34 to allocate production costs, the cost of production would have been increased by more than three cents per Mcf, from 11.0 to 13.5 cents per Mcf.

Q. What is the impact on the production cost of gas of using an economic factor of 1 to allocate production costs?

A. The impact is shown on line 12 of Exhibit 54. The unit production cost would be increased from the 11.5 cent cost used by the Commission in Opinion 546 to the 14.2 cent cost (line 12, Column C) derived by employing an economic factor of 1.

Q. Do the wide variations in the unit production cost of gas employing various relative cost ratios and economic factors which you have discussed show that a definitive production cost of gas cannot be determined with exactitude?

A. Yes. There are so many complex problems involved in the allocation of joint production costs that a specific level of costs cannot be allocated to gas with any amount of certainty.

Q. Please explain what you show on Exhibit 55, Mr. Larson.

A. I show in Exhibit 55 sample calculations of the type used in the various allocations summarized in Exhibits 52 and

[5,974]

54. Schedule 1 of Exhibit 55 shows a sample calculation of Continental United States exploration and develop-

ment cost for the year 1960 using an economic factor of 2.

Schedule 2 of Exhibit 55 shows the calculation of production unit costs for the years 1960, 1962 and 1969 using the relative cost method as applied by the Commission in Opinion 546.

Schedule 3 of Exhibit 55 shows the calculation of production unit costs for the years 1960, 1962 and 1969 using an economic factor of 2.

Q. Please explain what you show on Exhibit 56, Mr. Larson.

A. Exhibit 56 shows a range of unit costs for the years 1960, 1962 and 1969. Lines 1-6 show the calculation of unit costs using Opinion 546 methods. Lines 7-12 show the unit costs developed by using an economic factor of 2.34 to 1 for both the exploration and development function. Lines 13 to 18 show the unit costs developed by using an economic factor of 1 to 1 for both the exploration and development function. These results are shown in the table below:

[5,975]

	1960	1962	1969
Opinion 546	18.3¢	19.8¢	20.7¢
Economic Factor of 2.34	22.2	23.7	24.2
Economic Factor of 1	27.6	28.8	30.2

Q. Referring back to Exhibit 56, please comment on the appropriateness of the cost results shown above and which appear on lines 6, 12 and 18 of this Exhibit 56.

A. It would be inappropriate to use the low range of costs as shown on line 6 of Exhibit 56 as a basis for fixing rates. I have previously pointed out that judgment may be applied in numerous ways to a multitude of factors which make up these totals. The Commission in

Opinion 546 in most cases chose the lowest costs from the array of many costs presented. Line 18 of Exhibit 56 shows results near the top of the cost range. If actual costs were determinable, they probably would be somewhere in between those costs as shown on lines 6 and 18 of Exhibit 56. Therefore, rates based solely on costs at the bottom of the scale would be inadequate.

The selection of the lowest possible cost as was done in Opinion 546 might be all right if gas were purely a

by-product and if we were pricing out a large inventory which is to be sold off on a distress basis.

But here we are dealing with an industry which supplies 1/3 of the energy used throughout the whole United States. It is completely against the public interest to cost this resource on a by-product concept for then we dry up the supply and go out of business. The public interest demands replacement and enlargement and this can only be done by costing methods which realistically place natural gas on a footing more nearly equal to oil.

Having in mind these considerations, it would be much more appropriate for the Commission to determine costs at levels well above those shown on Line 16.

* * * *

[5,978]

TESTIMONY OF WILLIAM J. OGDEN

Q. Would you give your name and address please.

A. My name is William J. Ogden and my business address is 300 Park Avenue, New York, N. Y.

Q. What is your occupation?

A. I am employed by Commonwealth Services Inc. as an Executive Consultant.

Q. Will you briefly describe your educational and professional background?

A. I was graduated in 1958 from the Pennsylvania State University with a degree of Bachelor of Science in Petroleum and Natural Gas Engineering. I also attended St. Joseph's College from 1947 to 1950. At the time of my graduation, I was employed by the Gulf Oil Corporation as an engineer trainee in Hobbs, New Mexico. During my tenure with Gulf, I made studies of existing and prospective secondary recovery projects, evaluated drilling prospects, made reserve estimates and performed budgetary assignments as a member of the reservoir engineering section in the district office at Roswell, New Mexico. I also represented Gulf at unitization negotiations.

[5,979]

I was then assigned to the area office at Kermit, Texas where I was responsible for the engineering operations in various fields, including drilling and workovers. I was also responsible for the evaluation of the performance of the secondary recovery operations in the area and the allocation of power costs within the various fields. In 1962, I accepted employment with Public Service Electric and Gas Company in Newark, New Jersey. My duties

consisted of gas requirement studies, economic evaluations and apprising management of various aspects of the company's gas supply. I attained the position of Engineer of Gas Purchases and was responsible for many areas of the company's activities before this Commission. With the evolution of the area rate proceedings, I assisted counsel and the consultants employed by the Associated Gas Distributors in the conduct of the group presentation. This included evaluation of testimony presented to this Commission. In 1968, I was appointed as the Distributor representative to the Southern Louisiana Work Committee of the Potential Gas Committee.

I assumed my present affiliation with Commonwealth

[5,980]

Services Inc. in June of 1969.

Q. Are you a member of any professional association?

A. I am a member of the American Gas Association and the Society of Petroleum Engineers.

Q. Have you ever appeared as an expert witness before this Commission?

A. Yes. I have presented testimony in the Joint Hugoton-Anadarko and Texas Gulf Coast Area Rate Proceedings, Docket Nos. AR64-1 and AR64-2. I also presented under affidavit an estimate of the current cost of new gas-well gas for the United Distribution Companies (UDC) in response to the Commission's notice in Docket No. R-389A.

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by the UDC group to present the current national cost of new gas-well gas following the methods employed by the Commission in its previous opinions.

[5,980]

Testimony of William J. Ogden

Q. How did the Commission determine the current cost of new gas-well gas in Opinion 546?

A. The Commission used various Government and industry

[5,981]

statistical sources to estimate the individual components of the total new gas cost. The Commission relied upon the Census of Mineral Industries publication of the U. S. Department of Commerce to obtain average drilling costs per foot for oil wells, gas wells and dry holes. As the latest Census publication available to the Commission was prior to its test year, the Commission trended the Census figures using the change in the per foot cost of drilling reported in the responses to the 1960 questionnaire.

Annual drilling footage by type of well was obtained from *World Oil*, and annual additions of non-associated gas reserves were derived from the publications of the AGA reserves committee and the Bureau of Mines. From these data, the Commission derived reserve additions of non-associated gas per gas-well foot drilled. By dividing the average reserve additions per gas-well foot drilled over a select time period into the trended drilling cost per foot, the Commission arrived at a unit cost of drilling for both successful gas wells and dry holes.

[5,982]

Dry hole footage was allocated to gas-well drilling based on the ratio of successful gas-well footage to total successful footage drilled over the time period 1951-1961.

The unit allowance for lease acquisition costs was derived as a percentage of the unit allowance for successful gas-well costs. This percentage was based on the relationship of total estimated lease acquisition expendi-

tures as reported by the Chase Manhattan Bank, to a computed derivation of total successful well expenditures. Other investment costs were estimated as a percentage of successful well and lease acquisition expenditures based on the relationship of these items as reported in the responses to the 1960 questionnaire.

Other exploratory costs were derived by relating Geological and Geophysical expenses, lease rentals and other expenses to lease acquisition costs based on data published by the Chase Manhattan Bank over a selected time period. Exploratory overheads were estimated at a percentage of total finding costs.

Return on investment was derived by constructing a rate

[5,983]

base from the estimated successful well costs, lease acquisition costs and other investment costs. A return on working capital was also permitted, the working capital being based on the traditional one-eighth of cash expense, materials and supplies, and prepayments.

These data were derived from relationships reported in the 1960 questionnaire responses. The Commission also included a lease play allowance in working capital.

Other items of expense were based on data provided in the responses to the 1960 questionnaire and include production expenses, regulatory expenses, gathering and royalty. Production taxes were applied at the statutory rate.

Rather than allocate these items of cost between findings of non-associated gas and gas-liquid reserves, the Commission credited an estimate of the liquid revenue against the total cost.

Q. Has a document which has been identified as Exhibit 57 (WJO-1) been prepared by you, or under your supervision and direction?

A. Yes.

Q. Would you please turn to *Schedule 1* of your exhibit and explain the figures shown there.

A. Schedule 1 presents a summary of the new gas cost estimate employing the methodology used by the Commission in Opinion 468 and 546. The detailed computations deriving this cost estimate are presented in Schedule 2 of my exhibit.

Q. Would you explain the derivation of the figure for *Successful Well Costs* shown on *Line 1 of Schedule 1?*

A. Line 1 shows successful well costs of 4.43 ¢/Mcf. This figure was derived by dividing an average productivity of 587 Mcf per gas-well foot drilled into the trended drilling cost per foot for gas wells of $25.98. The average productivity of 587 Mcf per foot is based on the Commission's finding in Opinion 546. The trended drilling cost per foot for gas well is derived from the 1963 Census publication, the latest available data from this source for the total industry. The average drilling cost per foot for gas well drilling, excluding costs reported beyond the wellhead, is derived in Schedule 3, Sheet 1 of 2, in my exhibit. There, in

Line 5 Column 2, I show the gas-well drilling cost per foot of $15.76. The $15.76 figure is trended to 1969 using the reported change in the cost per foot for gas-well drilling from 1963 to 1969, from the responses to the questionnaire ordered in this proceeding. These data are shown in Schedule 3, Sheet 2 of 2 in my exhibit, being Lines 1 and 7 of Column 1, respectively.

Q. Turn now to *Line 2 of Schedule 1*, and explain the derivation of the figure for *Lease Acquisition Costs* shown there.

A. Lease acquisition costs are shown there to be 1.68 ¢/Mcf. The basis for the derivation of this figure is shown in Schedule 4, Sheet 1 of 2, in my exhibit. I have shown on Line 13 that for the period 1959 to 1969, lease acquisition costs averaged 38 per cent of the expenditures for total successful well costs. Applying the 38 per cent factor to the successful well costs derived in Line 1 of Schedule 1 results in a cost for lease acquisitions of 1.68 ¢/Mcf.

Q. Turn now to *Line 3 of Schedule 1*, and please explain the derivation of the figure shown there for *Other Investment Costs.*

A. Other investment costs are computed to be 0.52 ¢/Mcf. In Opinion 468 the Commission computed other investment costs to be a percentage of successful well costs and lease acquisition costs being a factor of 8.5 percent. I have adopted this finding of the Commission and applying the 8.5 per cent factor to the sum of successful well costs and lease acquisition costs derived in Lines 1 and 2 of Schedule 1 results in the 0.52 ¢/Mcf figure.

Q. Please explain the derivation of the *Dry Hole Costs* figure shown in *Line 4 of Schedule 1.*

A. I have computed the allowance for dry hole costs to be 2.15 ¢/Mcf. This figure is derived by trending the 1963 dry hole cost per foot of $8.69 (as reported by the Census) to 1969 by using the reported change in dry hole cost per foot from 1963 to 1969 from the responses to the questionnaire ordered in this proceeding. The trended dry hole cost per foot amounts to $12.97. The Commission in Opinion 546 stated that this trended figure needed to be adjusted for an assumed greater success ratio at greater depth and a higher cost per foot associated with deeper drilling.

The reasoning was that gas wells are typically drilled to a greater average depth than oil wells. The Commission found that the adjustment factor should be an increase in the trended dry hole cost per foot amounting to 8.28 per cent. I have adopted this finding of the Commission and derived a dry hole cost per foot of $14.04 applicable to gas well drilling.

The average productivity used by the Commission in Opinion 546 was adjusted in computing dry hole drilling cost to account for the amount of dry hole footage allocated to gas well drilling. The factor derived was 0.898 dry hole feet per gas-well foot drilled. Applying this factor to the productivity of 587 Mcf per gas-well foot drilled used in deriving the successful well costs in Line 1, gives an adjusted productivity for dry hole costs of 654 Mcf per dry hole foot drilled.

Dividing the adjusted dry hole drilling cost per foot of $14.04 by the adjusted productivity of 654 Mcf per dry hole foot results in the 2.15¢/Mcf figure.

Q. Turn now to *Line 5 of Schedule 1*, and explain the derivation of the figure for *Other Exploration Costs*

shown there.

A. I have computed other exploration costs to be 1.97¢/Mcf. The Commission derived Geological and Geophysical expenses, etc. as a percentage of lease acquisition costs. In Schedule 5 of my exhibit, I have shown that expenditures for G & G, etc. amount to 68 per cent of expenditures for lease acquisition costs over the 1965-1969 period as reported by the Chase Manhattan Bank. This figure is shown on Line 7 of Schedule 5. Applying the 68 per cent factor to the lease acquisition costs of

1.68¢/Mcf shown on Line 2 of Schedule 1 results in a figure of 1.14¢/Mcf.

In addition to this figure, the Commission in Opinion 546 found that exploratory overheads should be included amounting to 8.4 per cent of total finding costs. The total finding costs as I have estimated them amount to 9.92¢/Mcf, being the sum of successful well costs (Line 1), lease acquisition costs (Line 2), other investment costs Line 3), dry hole costs (Line 4) and the 1.14¢/Mcf figure for G & G, etc., above. The resulting allowance for exploratory overheads is 0.83¢/Mcf, and the total figure for other exploration

costs becomes 1.97¢/Mcf.

Q. Please turn to *Line 6 of Schedule 1*, and explain the derivation of the figure shown there for the *Adjustment for Exploration in Excess of Production.*

A. The adjustment for exploration in excess of production is necessary because of the Commission's decision to expense current exploration and development costs against current production rather than amortize these costs over the reserves added from the results of the E & D effort. The Commission recognized that since current production is not related to current E & D expenses, such an adjustment as necessary to avoid a mismatch of cost and production. The Commission in Opinion 546 found that reserves were currently being added at a rate of 137 per cent of annual production. The Commission therefore included an additional allowance amounting to 37 per cent of the computed exploration expenses in its new gas cost estimate. Applying the 37 per cent factor to the sum of the exploration expenses computed above on Lines 4 and 5 of Schedule 1. The results in a figure of 1.52¢/Mcf which is shown on Line 6.

[5,990]

Q. Please explain the derivation of the figure for *Production Expense* shown on *Line 7 of Schedule 1.*

A. In Opinion 546 the Commission utilized the expense data reported in the 1960 questionnaire responses to determine the allowance for production expense. I have used the 1969 production expenses reported in the responses to the questionnaire ordered in this proceeding. As shown in Line 5 of Schedule 6 of my exhibit, the allowance for production expense is 2.95¢/Mcf.

Production expenses were obtained from the responses to Schedule 5 of Packet B, using the total expenses reported there for the three gas lease types (gas only, gas condensate with lease separation and gas condensate without lease separation), exclusive of the annual provision for DD & A. From these expenses, miscellaneous lease revenues reported in Schedule 4 of Packet B were deducted.

Annual production volumes were also obtained from Schedule 4 of Packet B, exclusive of those volumes returned to the formation.

A unit allowance for production expense is derived by

[5,991]

dividing the adjusted expenses by the adjusted volumes. As the unit allowance was derived using the net working interest volumes reported (exclusive of royalty volumes), the unit allowance was adjusted for a 14 per cent royalty. A royalty adjustment is made for the total cost estimate on Line 14 of Schedule 1. The 14 per cent royalty adjustment used here is consistent with the 14 per cent royalty used in Line 14, and will be explained there.

Testimony of William J. Ogden

Q. Turn now to *Line 8 of Schedule 1*, and explain the derivation of the figure shown there for the *Net Liquid Credit.*

A. I have shown a net liquid credit of 4.65¢/Mcf. In Opinion 546, the Commission derived the net liquid credit from the responses to the 1960 questionnaire and I have used the responses to the questionnaire ordered in this proceeding in deriving the above liquid credit. These data are presented in Schedule 7 of my exhibit.

There I have shown the reported natural gas lease liquid revenues from gas wells and the plant liquid revenues credited back to the lease as reported in

[5,992]

Schedule 2 of Packet B of the questionnaire responses. The applicable production taxes have been deducted from the liquid revenues reported. The liquid production taxes are also reported in Schedule 2 of Packet B.

The revenues thus derived were divided by the gas-well gas production less those volumes returned to the formation also reported in Schedule 2 of Packet B of the questionnaire responses ordered in this proceeding. The resulting unit liquid credit was then adjusted for a 14 per cent royalty which gives the net liquid credit of 4.65¢/Mcf as shown on Line 10 of Schedule 7 in my exhibit.

Q. Turn now to *Line 9 of Schedule 1* and explain the derivation of the figure shown there for *Return on Investment.*

A. The return included in the new gas cost estimate was computed from an average rate base consisting of the capitalized costs shown on Lines 1, 2 and 3 of Schedule 1. The Commission assumed that the average reserve

would be depleted over a twenty-year period and therefore the average investment would be outstanding

[5,993]

for a period of ten years, or one-half of the total depletion period. The Commission also assumed that the average investment would also be outstanding for a period of one year prior to the receipt of any income from these investments. For this reason the Commission multiplied the above unit investments by a factor of 11 to determine the rate base upon which a return was to be computed.

I have used the factor of 11 as found by the Commission to be applied to the investments listed on Lines 1, 2 and 3 of Schedule 1. This results in a rate base of 72.93 cents per Mcf.

Applying a 13 per cent rate of return gives a return allowance of 9.48¢/Mcf.

Q. Did not the Commission utilize a 12 per cent rate of return in computing a return allowance in Opinion 546?

A. Yes.

Q. What is the basis for your using a 13 per cent rate of return in Column 1 of Schedule 1?

A. The basis for the 13 per cent rate of return is my understanding of the Staff recommendation in this proceeding as presented by Dr. Shaffner.

[5,994]

Q. Turn now to *Line 10 of Schedule 1* and please explain the derivation of the figure shown there for *Return on Working Capital.*

A. In Opinion 546 the Commission determined the allowance for Working Capital by using the traditional

one-eighth of cash expense, materials and supplies, prepayments and a lease play allowance. The lease play allowance was based on permitting the producers to maintain a cash balance directly for investment in acquiring new leases. Materials and supplies and prepayments were estimated as a percentage of exploration expense and production expense separately. The factors found by the Commission for exploration materials and supplies and prepayments were 39 per cent of exploration cash expense, and production materials and supplies and prepayments were 152 per cent of production cash expense. The lease play allowance was found to be 1.5 times lease acquisition costs. Applying these factors to the exploration cash expense (Lines 4, 5 and 6 above), production cash expense (Line 7), and lease acquisition costs (Line 2) gives a working capital allowance of 4.42¢/Mcf. Applying the 13 per

cent rate of return to working capital gives the figure of 0.49¢/Mcf as shown on Line 10 of Column 1.

Q. Please explain the derivation of the figure shown on *Line 11 of Schedule 1.*

A. This figure is the arithmetic sum of Lines 1 through 10.

Q. Turn now to *Line 12 of Column 1, Schedule 1* and explain the derivation of the figure shown there.

A. The unit costs shown on Lines 1 through 10 are at a pressure base of 14.65 psia. Line 12 converts the sum of these cost items to a pressure base of 15.025 psia.

Q. Please turn now to *Lines 13 and 15 of Schedule 1* and explain the derivation of the figures shown there.

A. Regulatory expenses of 0.15¢/Mcf and gathering expenses of 0.15¢/Mcf were derived by the Commission

in Opinion 546. These figures have been stipulated as being applicable for this proceeding.

Q. Please turn to *Line 14 of Schedule 1* and explain the derivation of the figure shown there.

A. The Commission in Opinion 546 provided a royalty allowance in the new gas cost estimate to compensate

[5,996]

the producer for the fact that he must bear the total cost of finding and producing natural gas although the royalty owner receives a portion of the revenue or production received from successful ventures. The individual cost items are estimated based on the total volume to be produced. The royalty adjustment restates these cost items to the producers' net working interest production. The Commission found in Opinion 546 that the applicable royalty was 14 percent for the nation as a whole. I have accepted this finding for the computation in Schedule 1. It must be pointed out, however, that the standard royalty for the Federal Domain offshore Southern Louisiana is a minimum of one-sixth, or 16.7 per cent.

Q. Please turn to *Line 16 of Schedule 1* and explain the derivation of the figure shown there.

A. Line 16 shows the Louisiana severance tax at the statutory rate.

Q. What does *Line 17 of Schedule 1* show?

A. It shows a total new gas cost of 27.58¢/Mcf reflecting the methods, factors and assumptions which I have enumerated above.

Q. Please characterize this cost figure as to exactness

[5,997]

and definitiveness.

A. This 27.58¢/Mcf cost of new gas resulting from the above application of Opinion 546 methodology is in no

sense an exact and definitive determination of the cost of finding new gas and no such precise cost determination can ever result from this method. As is evident from my previous discussion, the results of applying the Opinion 546 method are directly dependent on the available basic data input. The assumptions with regard to time periods, trends and other factors necessary to apply the Opinion 546 methodology will cause the results to vary widely—either above or below the 27.58 result depending on the judgments used to select the data, time periods, trends and other factors.

Q. Please give examples of such a variation from the basis which you have used in arriving at your result.

A. The 1963 Census figures are the base of most of the calculations in the Opinion 546 methodology. They are the latest available basic data the Commission has found acceptable for industry-wide drilling costs. When later 1967 Census figures become available and 1967 to 1969 trends are applied to them in lieu of 1963 to 1969 trends, the ultimate result will likely vary above or below

27.58¢/Mcf. The trend factor itself depends on whether one uses questionnaire data responses or JAS data as a base for determining the cost trend. Productivity is another extremely important factor in the Opinion 546 methodology. I have used the average productivity for the period 1947 to 1961 which the Commission in Opinion 546 determined to be a representative period. But future productivity may vary widely from this historical average and actual costs will vary either above or below 27.58¢/Mcf if another period is selected as being representative of probable future results. During some recent years, productivity has been materially higher than that achieved

in the 1947-1961 period, and, if assumed for the future, this would result in a cost less than 27.58¢/Mcf. But recent years during which producers were drilling fewer wells, and probably explored only better prospects, may not be representative of the future. If one expects an all out drilling effort, which necessitates the exploration and development of poorer fields, the productivity may fall materially below the results achieved in both the recent past and the "representative" period used in Opinion 546. This lesser productivity applied to the

[5,999]

basic data would result in a higher cost than the 27.58¢/Mcf. A further example is lease acquisition costs where industry experience was rather constant for many years but increased sharply in 1968 and 1969. I have used a figure based on experience during the 1959-1969 period. But use of a shorter experience period would result in a higher cost than 27.58¢/Mcf, and use of 1968 and 1969 experience would greatly increase this figure. Actual future costs may vary widely from any of these three factors which can be achieved from the industry data.

Q. In view of these uncertaintities inherent in the cost method, how do you as a petroleum engineer view the 27.58¢/Mcf cost resulting from your application of the Opinion 546 methodology?

A. I think it is a useful tool in rate making only if one most carefully weighs its frailties and does not push it beyond useful limits. It is a helpful guide but not an exact determination.

It is unrealistic to contend in these proceedings that any determination of this kind represents actual costs.

* * * *

[6,090]

TESTIMONY OF STEPHEN P. SHERWIN

Q. Are you the same Stephen P. Sherwin whose testimony appears at Tr. 2050?

A. Yes.

Q. What is the subject of your further testimony?

A. I have been asked to estimate the unit cost of finding and producing non-associated gas for:

1. The most recent period which the available data permit, so as to approximate a "current cost" estimate;

2. The period 1961-1968, representing the approximate time span specified by the Commission in Opinion 546 for "second vintage" gas.

Q. Would you please summarize the results of these studies?

A. I estimate the current cost of non-associated gas in the range of 28.37 to 36.12 cents per Mcf at an illustrative 13 percent rate of return and 31.46 cents to 40.11 cents per Mcf at a 16 percent rate of return.

I computed the average unit cost for the period 1961-1968 at:

	13 Percent Return	16 Percent Return
	(Cents per Mcf)	
1961-1964	22.63	25.08
1965-1968	27.30	30.31
1961-1968	24.97	27.69

[6,091]

Each of these several computations reflects an application of what may be termed the Opinion 546 method in-

sofar as the rate of return is applied to an average theoretical rate base, computed at one-half of the time period over which the investment is assumed to be outstanding. That kind of rate base is to be distinguished from a net investment rate base which gives consideration to the time value of money. If time value of money were reflected, the unit costs would be higher.

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[6,104]

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Q. How did you compute productivity of drilling?

A. Productivity of drilling is computed by relating reported reserve additions of non-associated gas to productive gas well footage drilled. For the current cost, I estimate the range of 555-600 Mcf per foot (Schedule 3); the results for the earlier years are shown in Schedule 4, Sheet 1.

There is only one source—the AGA reports—for the computation of reserve additions; but there are at least five alternative sources for

[6,105]

footage drilled: *World Oil, Oil and Gas Journal*, JAS, American Association of Petroleum Geologists, and the American Petroleum Institute. Where data are available for the same year from several sources, the variations in reported footage range up to 11 percent (Schedule 4, Sheet 2).

In past procedings, exclusive reliance has been placed on *World Oil* footage data. Of all the available sources, *World Oil* has for virtually all years reported lower footage figures than any alternative source. Use of *World*

Oil data results in relatively higher productivity figures, and therefore lower unit costs. On the average, *World Oil* reported 4 percent lower drilling footage figures than the JAS, the only other source which is available for each of the past 11 years. In the light of these facts, I shall rely on both *World Oil* and JAS data for footage figures.

Irrespective of the source used, the annual productivity data show a wide variation from year to year. I can discern no trend. The selection of an appropriate time period over which to average productivity is therefore a matter of judgment. In Opinion 546, the Commission computed productivity by reference to a 15-year average. If there

[6,106]

were a trend in productivity, it would be appropriate to look to a shorter time period, e.g., ten years.

I see no compelling reason for a choice between these alternatives, and shall therefore compute the range of productivity by reference to a moving average over both a 10- and a 15-year period.

By reference to the *World Oil* 10- and 15-year averages, the range of productivity for current costs is from 578 to 599; adjustment for a minimum 4 percent understatement of footage reported by *World Oil* results in a range of 555-575. The range is therefore from 555-599, which I rounded to 600. For the 1961-1968 period, I also computed a range of productivity for each of the years, by the same technique, but have used only the midpoint of the range in my summary cost computations. The results are shown in Schedule 3.

Q. You stated that there is no apparent trend in productivity, but is it not correct that the last seven years show a higher average than the last ten or fifteen years?

[6,106]

Testimony of Stephen P. Sherwin

A. Yes, but it would be erroneous to conclude that there has been a rise in productivity in the context in which the numbers are used in a current

[6,107]

cost study. The appropriate number of years over which to average productivity should be determined in the light of underlying economic conditions, not as a matter of mere statistics.

The apparent rise in productivity in the late 1960's is largely the result of the decline in the number of exploratory wells and the greater selectivity exercised in drilling programs. As the drilling effort declines, one must expect a rise in productivity because the best prospects are always drilled first. But it would be erroneous to assume that the productivity experienced in a period of clearly inadequate drilling activity may reasonably be anticipated in the near-term future if there are conditions of expanding activity. I therefore conclude that it would be misleading to rely on an average of the past seven years to

* * * *

[6,155]

ADDITIONAL DIRECT TESTIMONY OF DONALD W. AUTEN

Q. Will you state your name and address please?

A. Donald W. Auten of Tulsa, Oklahoma.

Q. Are you the same Donald W. Auten who has previously testified in these proceedings?

A. Yes.

Q. What is the subject of your additional testimony?

A. I am presenting evidence on the following additional subjects:

(1) Nonassociated gas estimated source and disposition of funds,

(2) Average gas well gas royalty percentage,

(3) Historical estimated costs of gas well gas in 1969,

(4) Estimated costs of Vintage 1 gas.

SOURCE AND DISPOSITION OF FUNDS

Q. Has Exhibit No. 64 (DWA-3) entitled "Nonassociated Gas Estimated Source and Disposition of Funds—1968" been prepared under your supervision and direction?

A. Yes.

Q. What does that exhibit present?

A. The exhibit presents the results of a study dealing with the availability of funds for exploration from nonassociated gas through internal generation and it takes the form of a cash flow analysis. A cash flow analysis summarizes those transactions from which cash is derived and for which cash is expended. The Federal Power Commission has indicated

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a strong interest in attempts to quantify the relationship between price and supply of natural gas, and I have prepared this cash flow analysis to focus on one of the important factors underlying decisions to explore for natural gas.

This analysis is subject to all of the uncertainties involved in analyzing the price-supply relationship, so that any attempt at quantification must be recognized as containing assumptions and estimates and therefore subject to qualification and limitations. Nevertheless, I believe the study does indicate one of the major reasons why, under past regulatory policies, the industry has not expanded or even adequately maintained levels of exploratory effort, and it does afford one basis on which the Commission can make an informed judgment as to how much additional revenue it may take to elicit the exploration and development needed to increase the supply of natural gas.

* * * *

[6,163]

A. Funds generated from revenues collected subject to refund are not really funds generated free and clear of at least some contingent liability. Although a producing company might be able to temporarily use such funds they must be prepared to refund them if necessary. Therefore, I considered that there would be a natural reluctance to commit those funds to finding new reserves so long as the refund uncertainty exists.

Q. What conclusions can be drawn from the study?

A. As I previously indicated, the study shows a deficiency in funds generated in excess of $600,000,000. The

deficiency is derived by use of cost estimates adopted by the Commission, its Hearing Examiners, or its Staff. To the extent that those cost estimates may be understated the deficiency is likewise understated. In order to eliminate the deficiency of $600,000,000 the average wellhead revenue for nonassociated gas (both interstate and intrastate) would have to increase approximately 5.1¢ per Mcf. Let me emphasize that I am talking about *average wellhead revenue* increase and not *area ceiling price* increase. An increase of 5.1¢ in average revenue would produce about $750,000,000 additional funds but 14% of that would flow to royalty owners and about another 7% of the balance would go to pay additional production taxes leaving net funds of about $600,000,000.

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[6,179]

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Q. Turning next to the adjustments that you have made for purposes of allocating and assigning exploration and development costs, how have you identified development dry hole costs with gas reservoirs?

A. The cost questionnaires provided for the reporting of development dry hole costs assigned to oil reservoirs and to gas reservoirs. Over 90% of the total development dry hole costs reported were assigned to the reservoir type.

Q. How does the reported data differ from the development dry hole cost data which were available in previous area rate proceedings?

A. In the Permian Basin proceeding the development dry hole costs assigned to the oil reservoirs or to the gas reservoirs were obtained by use of a questionnaire circulated by the producer respondents, and were not used

because the Commission found them not accetpable, saying that there was a considerable degree of self selection in the responses

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from the polled producers and that the data obtained were not the result of a random sample of all producers.

In the Docket AR61-2 proceeding the development dry hole cost data collection was again attempted in a questionnaire ordered by the Presiding Examiner. There again it was not utilized by the Commission because it was felt that the producers' failure to segregate some dry hole costs as between exploratory and development led to questioning the reliability of the data.

In the Hugoton-Anadarko and Texas Gulf Coast proceedings as well as in the Other Southwest proceedings the development dry hole cost data were reported in the Commission's All Area Questionnaires which requested the data by lease classification. Some of the reporting companies reported development dry hole data, representing 33% of the total, segregated by oil reservoirs or gas reservoirs instead of by lease classification. The Presiding Examiners in those proceedings misinterpreted the significance of reporting the data by reservoir type rather than by lease type and mistakenly decided against its use. For the purposes of assigning by hole costs to reservoir types either means of reporting can be used. There has been no specific Commission ruling on the reliability of that AAQ data for use in assigning costs to reservoir type.

In the current proceedings we have questionnaire data

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which should overcome the Commission's self selection or nonrandom sample objections and the Examier's objec-

tions as to data not in conformity with questionnaire instructions.

Q. Why is it proper to use the directly assigned development dry hole costs?

A. Development dry hole costs, by definition, represent the costs of those wells drilled to, or aimed at, specific reservoirs known to be in existence. Thus, if a development well is drilled to a gas reservoir, it can be identified as a gas reservoir development well. Similarly, if the development well is aimed at a reservoir known to exist and known to be classified as an oil reservoir, that development well can be classified as an oil development well. The mere fact that the well did not find production in commercial quantities and was classified as a dry hole does not change the nature of the cost. Consequently, the development dry holes can be directly identified with the type of reservoir, either oil or gas, to which they were aimed or drilled. This furnishes the only real basis for assigning or allocating the development dry hole costs to the two reservoir types.

* * * *

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* * * *

Q. Why have you normalized the exploration and development expenses in your estimation of historical gas well gas costs?

A. Under Commission practices of estimating costs based on a test year, one of the considerations necessary is the determination that the year or time period selected is a so-called normal period. If it is not, then some adjustment to the test year data is required.

The exploration and development expenses reported in the cost questionnaires in these proceedings reflect that the total dollar costs for each of the years 1965 through

1969 remained at practically the same level of $1,400,000,000. For the group of Appendix B and C companies reporting cost data in the Docket AR61-2 proceedings the dollar level of exploration and development expenses for each of the years 1956 through 1960 were approximately level at $1,100,000,000. The data reported in the 1962 FPC All Area Questionnaires indicated that the exemption and development expenses reported by those companies were approximately $1,200,000,000 in 1962 and they had been at about that same level for each of the years 1956 through 1962.

The three sets of cost data are not reported by identical groups of companies, but most of the major gas producers are included in all three sets of data and each set of data represents a significant percentage of the total industry.

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Therefore, I concluded that a comparison of the three sets of data would be useful in demonstrating the necessity for a normalization adjustment. The following table indicates the exploration and development expense levels compared to production volumes from the data noted above:

	Appropriate E&D Expense Levels	Approximate Production Volumes	
		Bbls. Liquids	Mcf Gas
AR61-2 Appendix B & C Companies—1960	$1,100,000,000	1,300,000,000	7,200,000,000
AAQ Companies—1962	1,200,000,000	1,400,000,000	8,900,000,000
AR69-1 Companies—1969	1,400,000,000	1,900,000,000	13,000,000,000
1969 as a % of 1960	127%	146%	180%

As that data shows there has been about a 46% increase in liquids production and about an 80% increase in gas production from the 1960 group data to the 1969 group data but the levels of exploration and development expenditures increased by only about 27%.

In the Commission's first area rate proceedings the exploration and development expense allowance for historical costing purposes was determined by allocating 1960 test

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year E&D expenses to 1960 production volumes. At that time the findings of both crude oil and natural gas exceeded production and I believe it is fair to say that the Commission recognized the necessity and desirability of maintaining a finding to production ratio in excess of 1. Based on the facts in the 1960 time period the Commission considered the level of exploration and development activity to be adequate or about normal for purposes of determining an E&D expense allowance in 1960. Thus the relatively greater increases in 1969 of both liquids and gas production as compared to the increase in exploration expenses shows that normalization of the expenses is necessary.

Q. How have you derived the exploration and development expense normalization factor used in your exhibit?

A. In order to adjust the 1969 exploration and development expenses in relation to production volumes up to the 1960 relationship the 1969 expenses should be increased in the range of 15% to 41%. I derive that range of increase from the observed increases in exploration expenses, liquid production volumes, and gas production volumes reflected by the AR61-2 cost questionnaires, the AAQ costs reported, and the 1969 FPC cost question-

naires. Since the expenses increased only 127% when they should have increased by at least 146% in order to match increased liquids production volumes the additional normalization factor required is

[6,189]

15%. Similarly expenses should have increased by 180% instead of 127% in order to match increased gas production volumes yielding a normalization factor required of 41%.

In view of the difficulty in separating the actual E&D expenses between oil and gas for the years 1960-1969 I am unable to determine exactly where in this range the appropriate normalization adjustment lies. I have chosen what I consider to be a conservative adjustment factor of 25% from the lower end of this range.

Q. Is the 1969 historical cost of gas well gas an appropriate cost of Vintage 1 gas as defined in Opinion 546?

A. No. Vintage 1 gas per Opinion 546 was gas flowing under contracts dated prior to January 1, 1961. Obviously, in 1969 we have gas flowing under many contracts dated after the Vintage 1 cutoff date and there is very likely a portion of Vintage 3 gas also included in 1969 production along with Vintage 1 and 2. Contrary to the situation in the earlier proceeding where the package of gas subjected to historical costing was a single vintage of gas, we now have a mixture of two or more vintages of gas in the historical costing data.

Q. Why when are you presenting the historical costs for 1969 in your exhibit?

A. Those cost computations are presented as the only type of historical cost computations available from the cost

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questionnaire data. Thus, if the Commission is to make any use of historical cost data in these proceedings, it presumably must be based on that available data. I do not believe the reporting of separate cost data for Vintage 1 or Vintage 2 gas would be feasible or practical.

By virtue of the Commission's Opinion 567 two or more vintages of gas may come from the same lease or property. There is no practical way to separately report costs and investments applicable to each vintage of gas produced from the same property. As time goes on such separate reporting becomes even more complex and arbitrary.

Q. Assuming that a Vintage 1 gas cost estimate is necessary in these procedings, are there any alternative ways of estimating such a cost from the available data?

A. Yes.

ESTIMATED COSTS OF VINTAGE 1 GAS

Q. Has Exhibit No. 67 (DWA-6) entitled "Estimated Costs of Vintage 1 Gas" been prepared under your direction and supervision?

A. Yes.

Q. What does that exhibit present?

A. In that exhibit I present two alternative methods for determining a cost of Vintage 1 gas as that gas is termed in Opinion 546.

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Q. Please describe the first alternative method of determining the cost of Vintage 1 gas.

A. That alternative method is presented in Schedule 1 of the exhibit. There I have shown the historical unit

costs as computed for 1960 in Option 546 (40 FPC 603) except that I have substituted the current cost DD&A and the current cost exploration expenses as computed by Dr. Sherwin in these proceedings for the same elements of the historical cost computation.

Q. What is the rationale for substituting current cost DD&A and exploration expenses in the Commission's historical cost computations?

A. The rationale is that the historical cost allowances should be sufficient to permit the finding of reserves equal to volumes produced during the period. As long as ceiling prices are based on costs the failure to allow current finding costs either means gas inventories cannot be replaced or else the producing industry must divert return allowance funds, otherwise available for growth in reserves, to the finding effort which would equate with production.

Q. Why isn't it appropriate to use the 1969 historical cost DD&A and exploration expenses instead of substituting the current cost for those elements?

A. That might be appropriate if we had a 1969 historical cost for Vintage 1 gas alone and if the 1969 cost elements were

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at the level required to bring forth the desired supply of reserves. However, I have earlier explained that the 1969 historical costs are not appropriate Vintage 1 gas cost measures and all indications are that 1969 finding efforts were well below those necessary to bring forth the desired supply. Consequently, the substitution of those 1969 historical cost elements in the determination of the appropriate Vintage 1 gas cost or price level would not permit reserve inventory replenishment. It would simply continue the declining supply situation.

To illustrate, if the Commission computes an historical cost in a test year when exploration effort is less than the necessary level it will derive a unit cost and, under past practices, establish a ceiling price which will be less than that required to support an adequate finding effort. In response to that price the producing industry will very likely further reduce the exploration effort in future years. Then in a second round historical cost computation a still smaller exploration and development cost will result and a further price reduction would be indicated. Such a policy would further depress supply instead of promoting the desired effect of increasing supply. The substitution of the current cost DD&A and exploration and development allowances in the historical cost computations helps to alleviate this problem.

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Q. Please describe the second alternative method of determining the cost of Vintage 1 gas.

A. The second alternative method is presented in Schedules 2 and 3 of the exhibit. The computation reflects a back-trending of the current cost of gas well gas which is presented by Dr. Sherwin in these proceedings. This method was used by the Commission in Opinion 468 where it adopted the Examiner's backtrending method as a check on its historical costing results. There the Commission said (34 FPC 219):

> "We think that the procedure used by the Examiner to arrive at his old gas-well gas cost is reasonable but that certain items of his computation require revision."

According to the Examiner and the Commission in that case the basis for such a backtrending of current costs

was that the gas produced in the test year resulted from exploration and development conducted during a series of years preceding the test year. Thus, the cost of drilling and equipping wells which produced gas in the test year was incurred in a span of about twenty previous years. Therefore, the investment costs and the return on investment costs derived in the current cost computations were reduced by a factor derived by relating a drilling and equipping cost index to the annual vintages of gas produced in the

[6,194]

test year. All other current cost elements were incorporated in the backtrended cost results without adjustment. I have followed that same procedure here to derive the backtrended cost of gas produced in 1969 which was under contracts dated in 1960 or prior years (Vintage 1 gas).

Q. Where did you derive the drilling costs per Mcf and the vintage data for gas flowing in 1969 as used in Schedule 3?

A. That information was derived by Mrs. Celia Gody, a witness in these proceedings, and I rely on her testimony for that portion of the evidence.

Q. What is the purpose of Schedule 3?

A. That schedule presents the computation of the factors used to reduce the investment costs and return on investment costs on Schedule 2. I have shown in the first column of Schedule 3 the 1969 jurisdictional gas sales under pre-1961 contracts vintaged by year of contract and expressed in percentage totaling 100. Those vintage percentages are then multiplied by the drilling and equipping costs per Mcf applicable to each of the years. The weighted average costs resulting are than totaled and that

total divided by the current successful well costs to derive the ratio of curent costs to Vintage 1 gas historical costs.

Q. Please continue with an explanation of Schedule 2.

A. In Schedule 2 I first show the current unit costs in 1969 derived by Dr. Sherwin. In the next column I show the factor

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derived in Schedule 3 which is multiplied by current unit costs of DD&A items and return on investment to compute the backtrended Vintage 1 costs. This backtrended cost, being lower than the 1969 current cost, requires a downward adjustment of the royalty cost which I have also made. The resulting backtrended cost of Vintage 1 gas is in a range of 21.83¢ to 28.92¢ per Mcf @ 15.025 psia.

* * * *

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TESTIMONY OF REID FELL

Companies Included in Composits
Southern Louisiana Area—Docket No. AR69-1 et al.
Year, 1969

Line No.	Code No.	Name	Packets B	C	D
1.	016975	Amerada Base Corp.	X	X	X
2.	017970	American Petrofina Co. of Texas	X	X	X
3.	029500	Ashland Oil, Inc.	X	X	X
4.	032020	Atlantic Richfield Co.	X	X	X
5.	032600	Austral Oil, Inc.	X	X	X
6.	034500	Astes Oil & Gas Co.	X	X	X
7.	108600	Cabot Corp.	X	X	X
8.	112125	California Co., Div. of Chevron Oil Co.	X	X	X
9.	141010	Cities Service Oil Co.	X	X	X
10.	149600	Cockrell, E., Jr., d/b/a Cockrell Corp.	X	X	X
11.	156500	Colorado Oil & Gas Corp.	X	X	X
12.	698500	Columbia Gas Development Corp. (formerly: Preston Oil Co.)		X	
13.	163650	Consolidated Gas Supply Corp.	X	X	X
14.	165000	Continental Oil Co.	X	X	X
15.	205400	Del Oil & Gas Corp.	X	X	X
16.	212605	Diamond Shamrock Corp.	X	X	X
17.	232360	Eason Oil Co.		X	
18.	252170	Exchange Oil & Gas Co.	X	X	X
19.	273500	Forest Oil Corp.	X	X	X
20.	294500	General American Oil Co., of Texas	X	X	X
21.	295000	General Crude Oil Co.		X	
22.	297390	Getty Oil Co.	X	X	X
23.	329000	Gulf Oil Corp.	X	X	X
24.	340000	Hamilton Brothers Oil Co.		X	
25.	376963	Highland Resources, Inc.		X	
26.	404500	Huber, J. M., Corp.	X	X	X
27.	408000	Humble Oil & Refining Co.	X	X	X
28.	411500	Hunt, Hassie Trust	X	X	X
29.	415000	Hunt Oil Co.	X	X	X
30.	456400	Kerr-McGee Corp.	X	X	X

* * * *

[6,330]

FEDERAL POWER COMMISSION
BUREAU OF NATURAL GAS

Docket No. AR69-1

AREA RATE PROCEEDING
(SOUTHERN LOUSIANA AREA)
Re: Gas-Well Gas Production Cost and
Exploration and Development Cost Allocation

TESTIMONY OF RAYMOND D. MURR

Q. What is your name?

A. Raymond D. Murr.

Q. By whom are you employed and in what capacity?

A. I am employed by the Federal Power Commission as a Supervising Regulatory Gas Utilities Specialist.

Q. What is your education background and experience?

A. I graduated from the University of Oklahoma with a Bachelor of Science Degree in Engineering in 1958. After a short period of employment with Otis Engineering Corporation at Lake Charles, Louisiana, I was employed by the Federal Power Commission in May 1959. I am a member of the Society of Petroleum Engineers of AIME and a Registered Professional Engineer in the State of Texas. I presented testimony and an exhibit allocating joint production costs in the Caroline Hunt Sands and Lloyd B. Sands case, Docket No. RI64-356. I presented testimony and exhibits relating to basic Btu data and production cost arrays in Docket Nos. AR64-1 and AR64-2 and small producer cost allocation in Docket No. AR64-1. Also, I presented testimony and an exhibit related to the allocation of joint production costs in Docket No. AR67-1.

* * * *

Table II

Comparison of Results of Production Cost Allocation Methods Combined with E&D Costs Allocated by Direct Assignment-Modified Btu Method Using Economic Factor of 2.5 for Liquids and 1.0 for Gas Year 1969

Description	Unit Cost—¢/Mcf @ 14.73 Psia			
	Relative Cost			
	Cont. U.S. Legs	So. La. Area Legs	All Cost [1] Assigned to Gas	By-Product Method
(a)	(b)	(c)	(d)	(e)
Production Costs				
Cash Expense	1.804	2.053	3.133	3.133
DD&A	4.002	4.547	5.063	5.063
Return @ 13%	5.460	6.181	6.821	6.821
Sub-Total	11.266	12.781	15.017	15.017
E & D Costs				
Expense	5.471	5.471	5.471	6.716
Return @ 13%	1.104	1.104	1.104	1.355
Sub-Total	6.575	6.575	6.575	8.071
Liquid Revenue	——	——	——	(5.559)
Total	17.841	19.355	21.592	17.529
Cost Allocated to Liquids (Excluding Prod. Tax)—$/Bbl.	2.88	2.05	0.82	3.05

* * * *

[1] Production Cost

[6,394]

TESTIMONY OF W. P. ANDERSON

Q. Will you please state your name and business address.

A. W. P. Anderson, 3000 Bisonnet, Touston, Texas.

Q. What is your present position?

A. I am employed by Panhandle Eastern Pipe Line Company as Vice President—Regulatory Affairs, and my responsibilities apply as well to Trunkline Gas Company, an affiliate of Panhandle. I am appearing in this proceeding for the Pipeline Purchaser Group.

Q. Will you please briefly summarize your educational and professional background?

A. I graduated from the University of Wisconsin in 1943 with a major in Accounting. Following a period of military service, I was employed in 1946 by the Public Service Commission of Wisconsin. During the next four years, as a member of the Accounts and Finance Division, I assisted the Commission in connection with gas, electricity, telephone and water matters. I joined Arthur Anderson & Co. in 1950 and for the next 13 years I was extensively engaged in accounting and auditing matters relating to regulated companies. I worked extensively with natural gas pipeline companies, among others. In my capacity as Senior and Manager in the public Utilities Division of Arthur Anderson & Co., I

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supervised preparation of material for presentation before regulatory commissions involving accounting, statistical, financial and economic data, and I appeared as a witness before regulatory commissions and in judicial proceedings. In 1963 I was employed by Panhandle East-

ern Pipe Line Company. I supervised the Rates and Economics Department in Kansas City, and later moved to Houston where I now supervise the regulatory affairs activity for both Panhandle and Trunkline. Our work involves preparation of statistical, financial and economic data for the company, including preparation of data for regulatory proceedings. I have been a Certified Public Accountant since 1950 and I am a member of the American Institute of Certified Public Accountants.

Q. Have you prepared studies for presentation in this proceeding?

A. I have supervised the preparation of a study to determine the average system-wide cost of transportation per 100 miles of haul, for the Southern Louisiana pipelines for which recent data were available. The purpose of this study is to demonstrate that the average cost of transporting hydrocarbons in gaseous form is approximately 2¢ per Mcf for 100 miles, or two-hundredths of a cent per MCF per mile. This material is

[6,396]

intended to confirm the reasonableness of the transportation fee for liquifiable hydrocarbons and related fuel, as set forth in Section 5.2 of the Settlement Proposal in this proceeding.

Q. Are the results of the study reflected in a summary?

A. Yes. We have prepared a summary which has been identified as Exhibit 25 (WPA-1) in this proceeding.

Q. How were the average unit transportation costs for these Southern Louisiana pipelines determined?

A. Simply stated, we accomplished all of the transmission costs for the pipelines involved in this study, resulting in what is essentially an industry transmission cost

of service. We then spread those industry transmission costs over the commodity miles of transmission for the same pipeline companies. This yields the unit cost of transporting each MCF, on an average basis.

Q. What was the source of the data for this study?

A. That data was taken from the filings submitted by the various pipeline companies to the Federal Power Commission in connection with recent rate proceedings. Page 2 of Exhibit (WPA-1) sets forth the summary of the transmission cost of service for each of the pipelines, and in the second column will

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be found the docket number of the rate filing from which this material was obtained.

Q. What is the transmission cost of service for these Southern Louisiana pipelines?

A. As reflected on the summary page of this exhibit, the total transmission cost of service for the seven pipeline companies used in the study is $1,088,697,591. The following page shows the breakdown for each of the companies, of the items making up the transmission cost of service, namely, operating expenses, depreciation, other taxes, return, federal income tax, and miscellaneous revenue credits.

Q. What is the next step in determining the unit transmission cost?

A. The next step is to determine the commodity miles for the same pipeline companies. In some instances this material was taken directly from the rate filings to which I referred earlier, and in other instances the data was derived from the company or from public records. The MCF transported per 100 miles is reflected on page 3 of Exhibit 85 (WPA-1) and the total for these Southern

Louisiana pipelines is shown to be 52,314,239,708. These commodity miles are also shown on the summary page of the exhibit. The average cost per MCF per 100 miles is

[6,398]

derived by dividing the total transmission cost of service by the commodity miles.

Q. What is the transportation cost as determined by your study?

A. The average cost is 2.081¢ per MCF per 100 miles. It would be appropriate to round this to 2¢ per MCF per 100 miles, or two-hundredths of a cent per MCF per mile.

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MR. MATTINGLY: I would request, or suggest, that Mr. Anderson's exhibit, entitled "Average System-Wide Cost of Transportation," be identified as Exhibit No. 85.

PRESIDING EXAMINER: Very well.

(THE DOCUMENT REFERRED TO ABOVE WAS MARKED FOR IDENTIFICATION EXHIBIT No. 85.)

MR. MATTINGLY: I would also suggest that there be copied in the record at this point the direct testimony of Witness J. L. Moye.

PRESIDING EXAMINER: Very well.

(The Direct Testimony of Witness J. L. Moye referred to above is as follows:)

[6,400]

DIRECT TESTIMONY OF JOHN L. MOYE

Q. Would you please state your name, business address and employment.

A. My name is John L. Moye; my business address is P. O. Box 2511, Houston, Texas, and I am Director of Planning for Tennessee Gas Pipeline Company, a Division of Tenneco Inc. My responsibilities include supervision of pipeline design for Tennessee Gas Pipeline Company. In addition, I supervise pipeline design for three pipeline subsidiaries of Tenneco Inc.

Q. Would you please describe your educational background and experience.

A. In 1949, I received a Bachelor of Science in Petroleum Engineering from the University of Texas. After graduation from the University of Texas in 1949, I was employed by the Magnolia Petroleum Company (now Mobil) for five years as a Petroleum Engineer. During my employment with Magnolia, I was engaged, in Louisiana and Texas, primarily in oil and gas well drilling and completions, corrosion control, oil and gas well testing, preparation of oil and gas reserve studies, special projects such as secondary recovery and pressure maintenance, and reservoir engineering studies.

In February 1954, I accepted employment with Tennessee in its Reserves Department in Houston, Texas. My duties were preparation of oil and gas reserve studies of company owned oil and gas properties and of the gas reserves dedicated under contract to Tennessee. My work also included evaluation of oil and gas properties for prospective purchase.

[6,401]

In 1962, I was transferred to the Planning Department and promoted to Assistant Planning Manager in charge of Gas Storage for Tennessee and the subsidiary pipelines. In April of 1969, I was promoted to my present position as Director of Planning. My responsibilities include supervision of pipeline design (including two-phase testing) and underground gas storage.

Q. Are you a registered professional engineer and do you belong to any related professional societies?

A. I am a registered professional engineer in the State of Texas and a member of the American Institute of Mining, Metallurgical and Petroleum Engineers.

Q. Briefly state the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to provide, in connection with Section 5.2 of the proposed settlement in these proceedings, a reasonable basis upon which the Commission can reach a conclusion regarding a charge for two-phase pipeline transportation of liquids for producers in connection with the pipeline purchases of natural gas in the Southern Louisian area. By liquids, I mean the liquid hydrocarbons produced with gas, commonly termed condensate.

Q. Are you familiar with the testimony and exhibit prepared by Mr. Page Anderson for presentation in this proceeding?

A. Yes. Mr. Anderson's testimony indicates an industry average system-wide cost of 2¢ per Mcf per 100 miles for transportation of natural gas. Mr. Anderson's determination is used in reaching my conclusion regarding a charge for pipeline transportation of liquid hydrocarbons in connection with pipeline purchases of natural gas.

[6,402]

Q. What conclusions have you reached regarding a charge for pipeline transportation of liquids in connection with purchases of natural gas?

A. Because of the many variables involved, such as liquid-gas ratios at points of production or receipt, total volumes of liquids, distance from points of gas production to points of liquid separation, operating pressures of particular pipeline systems, and availability of liquid storage facilities, no single formula can be used to determine an appropriate charge which should be assigned to the transportation of liquids in all situations. On the other hand, an industry approach, based on average industry system-wide experience and employing a flat rate per barrel of liquids transported, would not only be administratively feasible, but would provide a degree of certainty as to the cost which producers may anticipate in situations where a purchasing pipeline agrees to transport liquids produced in association with natural gas.

Q. In addition to Mr. Anderson's average industry-wide cost of 2¢ per Mcf per 100 miles for gas transportation, are there other factors which affect your recommended charge for pipeline transportation of liquids in connection with purchases of natural gas?

A. There are two other factors which directly affect my recommendations—the effect of liquids on pipeline capacity or efficiency, and the average liquid-gas ratio in a pipeline.

In transporting liquid hydrocarbons in a two-phase stream with natural gas, Tennessee has experienced an average reduction in pipeline capacity of approximately 13% as compared to a pipeline

carrying gas only. The determination of such average capacity reduction is based on the "Tennessee correlation" for design of two-phase pipelines. Such correlation was derived from evaluations of extensive data obtained in the operation by Tennessee of various size two-phase pipelines. The "Tennessee correlation" is a plot of Panhandle "A" Efficiency versus Two-Phase Velocity, and is graphically illustrated in my exhibit, J.L.M. No. 1 (Exhibit No. 86).

The stated average reduction in pipeline capacity of 13% is the rounded arithmetical average of the percent reduction in capacity for each of the varied sets of conditions shown in my exhibit J.L.M. No. 2 (Exhibit No. 87), "Percent Reductions in Throughout, Two-Phase versus Gas Only."

It has been Tennessee's experience, based on recent data as shown in my exhibit J.L.M. No. 3 (Exhibit No. 88), that the two-phase transmission of liquid hydrocarbons and gas involves an average liquid-gas ratio of approximately 15 barrels per MMcf. The composite arithmetical average liquid-gas ratios by months shown in the exhibit reflect deliveries of liquids at the Grand Chenier and Cocodrie separation facilities through Tennessee's two-phase gas supply systems. These systems supply 1.2 billion cubic feet per day, or approximately 30 percent of Tennessee's daily requirements.

We have been advised by Transcontinental Gas Pipe Line Corporation and Trunkline Gas Company that they both have experienced similar averages of liquid gas ratios and percentage reductions in capacity

as a result of liquid transportation in two-phase operations.

Q. Please outline your determination of a recommended charge for transportation of liquid hydrocarbons in a two-phase pipeline system.

A. From the indicated averages of percent reduction in pipeline capacity and liquid-gas ratios, an average charge of 20¢ per barrel can be derived for transporting liquid hydrocarbons, based on the industry average system-wide cost for moving gas of 2.0¢/100 Mcf miles.

$$\frac{\text{The Equivalent Cost to Transport Liquids}}{\text{Bbls. of Liquid}}$$

OR

$$\frac{0.13 \text{ Liquid Fraction} \times 2.0¢/\text{Mcf} \times 1{,}000 \text{ Mcf/MMcf}}{0.87 \text{ Gas Fraction} \times 15 \text{ Bbls./MMcf}} = 19.9¢/\text{Bby. or } 20¢/\text{Bbl}$$

For example:

Assume:

Transmission capacity (no liquids)	=	100,000 Mcfd
Transmission capacity (with liquids)	=	87,000 Mcfd
Liquid equivalent capacity	=	13,000 Mcfd
Distance hauled	=	100 Miles
Barrels liquid	=	15 Bbls./MMcf
Total barrels (87 x 15)	=	1,305/day

Then:

Total equivalent cost to transport Liquids ($.02 x 13,000)	=	$260/day
Equivalent cost per barrel $\frac{206}{1{,}305}$	=	$.199 or $.20/Bbl.

[6,405]

Q. Please explain the propriety of using an assumed 100 miles as the distance of transportaing liquids in the application of your formula.

A. Although the average distance that Tennessee, Trunkline and Transco have transported producer liquids has been approximately 60 miles, it is expected that in the future, the distances will be greater and will soon approximate 100 miles. For example, during the December 15, 1970 offshore Louisiana lease sale, 116 leases were sold. The estimated average pipeline distance to an onshore separation facility from these leases would exceed 100 miles.

Q. Do the pipelines and the public benefit from the pipelines' undertaking to transport producer liquids in connection with purchases of natural gas?

A. In situations where the liquids are not transported with the purchased gas and a producer cannot economically arrange for delivery of his liquids into a liquid pipeline, the only alternative is to barge the liquids to onshore storage locations. This requires the installation of additional liquid storage facilities at the offshore producing platforms (where space is at a premium) awaiting intermittent barge pick up.

The pipeline purchaser, in undertaking to transport the producer's liquids to an onshore location, not only eliminates the expense of the producer's offshore storage facilities, but most importantly, helps to improve continuity of the gas service for its customers. Many of the major pipelines obtain a substantial part of their gas

supply from two-phase supply systems. Tennessee, for example, presently obtains approximately 30% of its total supply via two-phase supply systems. If the producers making deliveries of gas to the pipelines were barging their associated liquids instead of delivering such liquids into the pipeline, then based on Tennessee's experience,

such gas supplies could have been interrupted as much as 10% of the time because of weather and other problems preventing the operation of barges.

In the event of such an outage, Tennessee would not be able to load its supply system, thus exposing its customers to possible temporary curtailments in service. Alternatively, to assure and maintain full service during periods when gas wells are shut-in because of interruptions in barging operations, Tennessee would have to provide sufficient underground storage (assuming that it would be available). Based on Tennessee's present average cost of existing underground storage of approximately 18¢ per Mcf, if a producer normally able to deliver 100,000 Mcf per day were shut-in 10% of the time, underground storage service costing approximately $657,000 annually ($.18 x .10 x 365 x 100,000) would be required to meet the deficiencies in deliveries. This compares to the equivalent cost of approximately $94,900 per year ($260 x 365) indicated above to transport the producer's liquids to avoid this type of interruption in gas production. In addition, it should be kept in mind that the current cost to acquire and develop additional storage would be more than the 18¢ per Mcf average cost of existing storage|

[6,407]

Q. Please explain your reasons for recommending a flat rate for pipeline transportation of liquids, rather than a variable rate reflecting distance from the point of production to a point of separation.

A. The transportation of liquids in a pipeline with gas is not susceptible to a mileage charge because the introduction of gas containing free liquids at any point on a pipeline has the net effect of reducing the efficiency of the entire pipeline as though the total gas stream con-

tained liquids. Also, unlike the introduction of an additional volume of gas into a pipeline where the effect on the system is directly attributable to the volume introduced, the introduction of additional volumes of liquids into a two-phase pipeline has no detrimental effect on the operation of such pipeline that is related to miles hauled.

Q. In addition to the reliability of service benefits, are there any other benefits to the public resulting from the transportation of liquids in connection with pipeline gas purchases?

A. Yes. Without attempting to evaluate them in a precise manner, the transportation of liquids in connection with pipeline gas purchases reduces the risk of liquid spillage and water pollution in the Gulf of Mexico and/or inland waterways from handling accidents, either at the offshore platforms or during barging operations. The public in general thus obtains what may be termed an "environmental" benefit which, of course, is not readily measurable in dollars. In addition, the transportation of liquids in connection with a pipeline purchase of natural

[6,408]

gas could promote the recovery of marginal gas reserves on leases where it would not be economical to install liquid storage facilities for barging operations, thus aiding in the conservation of valuable natural resources.

* * * *

[6,410]

Subject to your approval, it might be helpful if that were copied into the record for the benefit of the parties.

I have contacted the parties, and to my knowledge it is agreeable to all the parties.

PRESIDING EXAMINER: Staff Counsel has suggested that Staff Witnesses be examined as follows:

February 2 Mr. Fell and Mr. Bateman;
February 3 Mr. Murr;
February 4 Mr. Guevara;
February 5 Mr. Loring.

It is understood, however, that the witnesses to follow the last of Staff Witnesses will be available in the event that cross examination of Staff Witnesses should be concluded more rapidly than as originally scheduled.

Does that finish?

MR. MATTINGLY: I believe so.

MR. SAPONARO: Yes, sir.

PRESIDING EXAMINER: Fine.

We are now adjourned until February 2, 1971, at which time we will commence with the cross examination of Staff Witness Fell.

(Thereupon, at 10:50 a.m., the hearing in the above-entitled matter was adjourned, to reconvene on Tuesday, February 2, 1971.)

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* * * *

[6,416]

TESTIMONY OF REID FELL

to reservoir type"—"to the reservoir type indicated as the primary object of the search. Such amounts shall reflect assignments made prior to the expenditures involved."

Would you explain exactly what that means?

A. Well, as I understand it company personnel know, in some areas, what type of reservoirs there are, and they know what they have—they had an idea, at least, what they were looking for, before they made the search. And these are the amounts expended that they were able to tie down to their estimated search.

Q. You say some of the personnel know what they are looking for before they begin the search.

Do the companies——

A. That is my understanding. I have no further knowledge than that concerning this subject. That is my understanding.

Q. What kinds of records do the companies keep with respect to the assignment of costs prior to drilling?

A. It is my understanding that they report certain items of this nature to the state commissions of the states in which they are doing the drilling, like the Louisiana Commission and so forth.

Q. Do I understand, then, before they actually drill a hole in the ground they make a record that they expect to get gas out of this particular hole, or that they expect to get oil?

A. I understand the state commissions require some type

[6,417]

of a record of this type. I am not real familiar with this record.

PRESIDING EXAMINER: Would how the company keeps its records be within the knowledge of this witness? And would it not vary from company to company?

MR. MORROW: That is what I am trying to find out. I am trying to test these figures and find out whether they came from uniform records of all of the companies, or were compiled on the same basis by all the companies, whether they represent a representative portion of the companies, or exactly what these figures are. From the instructions on page 5 and the numbers themselves I have no way to test their validity.

What I am getting into now is to try to find out what sort of records we have that were used as the basis for these numbers.

BY MR. MORROW:

Q. Mr. Fell, you say you don't know exactly how the companies went about assigning dollars to particular drilling efforts prior to the beginning of drilling?

A. No, I do not. I accept the figures reported on the schedule that was filed with the Staff, with this schedule.

Q. Do you know how many of the companies you reviewed made these prior assignments of expenditures?

A. No, I don't. I don't know. I did not look into this particular schedule, in my field review.

* * * *

was in conformance to, and generally followed, the questionnaire instructions.

It is the Staff's position on that data that we accepted it, as filed, as reasonably reliable, and we accord it the same weight and it is to be judged in the same manner as any other data reported on the questionnaires.

PRESIDING EXAMINER: Where did the figures come from that were furnished to Staff? There was no effort made to determine where they came from?

MR. MATTINGLY: Staff made a field audit. The question is how much detail. You go beyond the company reports back——

PRESIDING EXAMINER: Mr. Morrow's question runs to where the figures came from.

MR. MATTINGLY: I don't think that kind of detailed audit was performed.

PRESIDING EXAMINER: And the witness does not know where the figures are taken from.

Is that correct?

THE WITNESS: I don't know precisely, Mr. Examiner. The records are kept by all these respondents, these fifty companies, where they record this information.

PRESIDING EXAMINER: All right.

BY MR. MORROW:

Q. Do you know how the companies went about making the decision that a particular project was going to be for oil and

another project was going to be for gas? How did they make the determination in advance?

A. That was their determination, Mr. Morrow. I did not—they made it.

Q. You don't know whether all the companies used the same standards or test or criteria to make that decision, do you?

A. No, I do not.

Q. Do you know what the reason was for making these prior assignments, other than the general rumor, or information, that they may have been mailed for a state regulatory commission?

MR. MATTINGLY: The witness has said he doesn't know the basis on which these assignments were made.

BY MR. MORROW:

Q. Was there any other reason for the companies to make these assignments, any business reason, any purpose to be served, other than to meet the requirements of state regulatory agencies?

PRESIDING EXAMINER: Isn't that a question better asked of a company witness?

MR. MATTINGLY: It is not within the knowledge of this witness.

MR. MORROW: I don't know, Your Honor, what witness to ask it of.

This witness presented these figures. The Staff says these

[6,421]

figures are reliable. So far I have not seen anything on which I could base much reliance.

PRESIDING EXAMINER: He told you where he got them from.

He says he doesn't know what they are based on. Whether you place reliance on them is for you to determine.

MR. MORROW: It is a question of whether the Commission can place reliance on them.

PRESIDING EXAMINER: I think you have already determined that.

MR. MORROW: All right, sir.

BY MR. MORROW:

Q. You say the amounts reflect assignments made prior to the expenditures involved, in your instructions.

Does that imply that the company has already determined whether it is searching for oil or gas, before it records its expenditures?

A. No, sir.

Q. It does not mean that?

A. The expenditures recorded in their financial records are recorded, naturally, after the expenditures are made.

These records would be something other than that.

Q. Did you make a check to be certain that the assignments with respect to oil and gas, which were reported by the companies, were assignments made prior to the expenditure of the dollars involved?

[6,422]

A. No. I made no check of this schedule whatsoever, other than to verify the amounts recorded on the questionnaires when they came into Washington.

Q. How did you verify those amounts?

A. "Verify" is not a good word here.

I took the amounts that were reported on each—for each company, and all the revisions involved, and applied those revisions and reported the totals in this composite.

Q. What revisions are you speaking of, Mr. Fell?

A. We have many revisions to all these schedules.

Q. Would you explain what revisions you made of the company figures, generally?

A. For any schedule?

Q. No. For this particular schedule.

A. I don't know for this particular schedule, without looking at my records.

Q. Do you know whether revisions were made to the company figures in this particular schedule?

A. No, I do not, without looking at each filing that was filed, to see if they filed a revision for this particular schedule.

I do know generally that we received lots of revisions.

Q. Did you receive them from the companies?

A. Yes, sir.

Q. First, you received the answers to the questionnaires,

* * * *

[6,431]

those for the convenience of the parties. But those footnotes have been on file for a long time on the basis of the original reports filed.

PRESIDING EXAMINER: If Mr. Morrow wants to research those footnotes he may, and if he wants to question the witness further later I will permit it.

Does anybody else wish to cross examine this witness?

MR. BRUCE: I have one additional question, Your Honor, if there are no others.

PRESIDING EXAMINER: All right.

BY MR. BRUCE:

Q. Do you have any reason to believe, Mr. Fell, that the data shown on schedule 3 of this exhibit is of any greater or lesser degree of reliability than any of the other data in your exhibit?

A. No, I do not.

MR. BRUCE: That is all, Your Honor. Thank you.

PRESIDING EXAMINER: Are there any further questions from this witness?

(No response.)

PRESIDING EXAMINER: Thank you. You are excused, Mr. Fell, subject to recall should Mr. Morrow request it.

(Witness excused.)

PRESIDING EXAMINER: Mr. Bateman.

Has he testified before in this proceeding?

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* * * *

[6,484]

TESTIMONY OF C. M. ALLEN

* * * *

C. M. ALLEN

was called as a witness and, having been previously sworn, was examined and testified as follows:

PRESIDING EXAMINER: You are reminded that you have been previously sworn in this proceeding.

THE WITNESS: Yes, sir.

* * * *

[6,485]

* * * *

CROSS-EXAMINATION

BY MR. MORING:

Q. Mr. Allen, in connection with time lag I wanted to ask you a question or two about advance payments.

You are familiar with the term "advance payments", are you not?

A. Yes.

* * * *

[6,486]

* * * *

MR. MORING: This would be my next question, i.e., How would Mr. Allen define "advance payment"?

THE WITNESS: I assume what you are talking about, Mr. Moring, is the payment by the gas purchaser to the owner of the gas, payments made prior to delivery of the gas and then made up for after delivery begins.

BY MR. MORING:

Q. Right. Do you know of any specific occasion where this has occurred?

A. I know they have occurred, Mr. Moring. I do not have any details on any of them.

Q. Let's take this illustration:

Suppose a producer had successfully bid for some leases in the offshore area, and had been awarded a lease by the Department of Interior on, say, last December 15. If he were able to work out with a pipeline, say, an advance payments arrangement whereby his lease bonus would be paid now by the pipeline, how would that affect this time lag study?

A. Taking all of your assumptions into account, on that particular—He never pays the lease acquisition cost at all? When he bids he has to put up 20 percent.

[6,487]

Q. Right. Let's take that case.

A. Then he is immediately repaid that 20 percent plus the other 80 percent?

Q. Yes. What does he have, 30 days, to pay the balance?

A. I believe it is on that order.

At any rate, on that particular transaction his time lag would be very short, because he would not have an investment.

Q. I see.

A. But I don't believe I would characterize that as a general happening in the industry. Those would be short when they happened.

Q. And the impact of that kind of transaction would be, in terms of time lag, to reduce your time lag figure, is that correct?

A. Well, yes. It would tend in the direction of reducing it; but, now, there are other factors which in reality, and I think in more general cases, would tend to lengthen it.

You see, the average sale of gas is on something like a monthly settlement period. And most gas is sold that way. So instead of receiving income on the first day of production, as it has been figured in this time lag study, it would be at least 30—probably closer to 45—days later that the revenue would flow.

Q. That is covered by working capital, is that correct?

A. How is it covered. You mean——

[6,488]

Q. Is this kind of lag contemplated by the working capital allowance?

A. I don't know.

Q. You are saying there is a time lag between the time you commence production until the time you get your first payment?

A. Yes. I was pointing out, wanting to make it clear that this particular data that was gathered was from the date of first production of the well, not from the detail that revenue came in.

Q. Mr. Allen, do you know whether—you have looked at Mr. Auten's time lag computations, have you not?

A. The cost composite, his testimony, yes.

Q. Did he weight his lease acquisition time lag by bonus money?

A. Yes.

Q. Would that bonus money be reduced to the extent of advance payments of the kind we just used in that example?

A. Well, yes. They may well be reduced by some of those things in this study.

* * * *

[6,494]

TESTIMONY OF STEPHEN P. SHERWIN

PRESIDING EXAMINER: The material in there, did you write it specifically for this publication?

THE WITNESS: I wrote Part 2. I made a study for the Bureau of Land Management.

After I made the study for the Bureau of Land Management it became the property of the Department of the Interior, and the Department can do with it what it likes. It chose to make a publication out of it. I am not certain that it took the entire study, or that it took only parts of it.

That is the only hesitation I have with respect to saying whether or not this is a full and complete——

PRESIDING EXAMINER: Did you ever look at it again after it was published?

THE WITNESS: No, I did not.

PRESIDING EXAMINER: Go ahead, Mr. Moring.

BY MR. MORING:

Q. 197 is the page I wanted to look at particularly. I see a heading "Revenues from Non-associated Gas Reserves." Do you see that?

A. Yes, sir.

Q. Those revenues include, I believe, three elements —non-associated gas, lease and plant condensate, and, thirdly, other plant liquids. Is that the way this table is laid out, that you prepared?

A. Yes.

* * * *

[6,611]

TESTIMONY OF WILLIAM J. OGDEN

DIRECT EXAMINATION

BY MR. JONES:

Q. Will you please state your name and address?

A. William J. Ogden, 300 Park Avenue, New York City.

Q. Are you the same William Ogden whose testimony appears at transcript pages 5978 through 5999?

A. Yes, sir.

Q. I invite your attention to a document entitled "Estimate of the Current Cost of New Gas Well Gas Per Opinion Nos. 568-546," which has been identified as Exhibit 57 in this proceeding. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, sir.

Q. Do you have any corrections for this exhibit?

A. I have.

Q. Will you please give us those?

A. On Schedule 2, Sheet 2, line 3, the multiplication sign should be changed to an addition sign, so line 3 would read "1.14 plus 0.03 equals 1.97 cents per Mcf."

Again on Schedule 2, Sheet 4, line 3, the figure of 4.74 cents per Mcf should read 24.77 cents per Mcf.

On line 4 of that same sheet, the 24.74 should read 24.77.

On Schedule 7, line 5, the figure 7630374 should be 7891374.

[6,612]

That is the extent of my corrections.

Q. Do these corrections which you have made result in any changes in your testimony?

A. No, sir.

Q. Do they make any substantive change in the result of your exhibit?

A. No. They are typographical errors.

Q. Do you have any corrections to your testimony?

A. No, sir.

Q. Do you adopt this testimony as your testimony in this proceeding?

A. I do.

MR. JONES: Your Honor, I move that Exhibit No. 57 be received in evidence.

PRESIDING EXAMINER: It will be received.

(THE DOCUMENT REFERRED TO, MARKED EXHIBIT 57 FOR IDENTIFICATION, WAS RECEIVED IN EVIDENCE.)

MR. JONES: I offer Mr. Ogden for cross examination.

MR. GOLDBERG: Don't you have a correction to make in your testimony on line 22 at transcript 5993? Shouldn't "Dr. Shaffner" be "Mr. McGrath?"

THE WITNESS: I think you are right, Mr. Goldberg. You are right.

* * * *

[6,624]

* * * *

REDIRECT EXAMINATION

BY MR. JONES:

Q. Mr. Ogden, Mr. Goldberg asked you a question with respect to the 1.37 factor in the Commission's opinion. Can you tell us how that adjustment was made by the Commission?

A. In Opinion 468, where it first appeared, the Commission did not give any particular derivation of the

factor; it was a matter of judgment in which they selected this particular adjustment.

In Opinion 546 they made a computation which attempted to support this particular factor.

Conceptually, what they did in Opinion 546, they took the 1961-66 gas well drilling figures and multiplied by the average productivity over the 1947-1961 period to compute an imputed findings, which they then compared with actual production to support the 1.37 factor.

Q. Actual production in what year?

A. For the same 1961-66 period. It was an average of that whole period.

Q. Does the fact that production exceeded findings in 1968 and 1969 have anything to do with the use of this factor in your exhibit?

A. Not in my understanding of the Commission's determination of the factor.

* * * *

[6,626]

TESTIMONY OF CHARLES A. LARSON

* * * *

DIRECT EXAMINATION

BY MR. JONES:

Q. Will you please state your name?

[6,627]

A. Charles A. Larson.

Q. Are you the Charles A. Larson whose prepared testimony appears at transcript pages 5925 through 5976 in this proceeding?

A. Yes, I am.

Q. Were Exhibits 51, 52, 53, 54, 55, and 56 for identification prepared by you or under your direction and supervision?

A. Yes, they were.

Q. Do you have any corrections to this testimony?

A. Yes. I have several transcript corrections.

Q. Would you give us those, please?

A. The first appears on transcript page 5926, line 7. The word "Continental United States" should be deleted.

The next transcript correction appears on transcript page 5951, line 9, where the number "57" should be inserted in the blank.

PRESIDING EXAMINER: Did you say "57"? Mine already has the "57" in it.

THE WITNESS: The same adjustment should be made on the next page, 5952, on line 13.

The next correction appears at transcript page 5965, line 19. In the brackets "1,461" should be "1,508."

BY MR. JONES:

Q. Does the same correction appear on the following

[6,628]

line; should it appear?

A. No.

Q. Line 20?

A. No.

The next correction is on page 5972, line 5; the word "at" should be replaced by "that it".

The next transcript correction appears at page 5973, line 3; change the three words "by more than" to the word "almost".

The final transcript correction appears on page 5976; at line 15 "line 16" should be "line 6".

Q. Do you have any corrections to your exhibits?

A. Yes, I do have.

Q. Will you give us those, please?

A. Starting with Exhibit 51, Schedule 3, sheet 1, Column C, line 8, the figure appearing there of 5,319,091 should be 5,391,091.

Schedule 4 of Exhibit 51, sheet 2, at the bottom of the schedule, just opposite the word "source" the letters in brackets should be changed. The first line on the source, "Columns A and B" should be "Columns C and A".

In the next line "Column C" should be "Column F".

The next line, "Column D" should be "Column B".

In the next line "Column E" should be "Column D".

On the following line "Column F" should be "Column E".

[6,629]

On Schedule 4, sheet 3, the same exhibit, I need to change some of the column designations. The first is in the third line in the source reference. Toward the end

of that line there is a reference to Column C, and that should refer to Column F.

On the sixth line, where it starts out "Column G lines 1-6," the reference to "Column E" should be to "Column D".

Two lines below, starting "Column I, lines 1-6", the reference to "Column F" should be a reference to "Column E."

Dropping down to line 9, Column B-A, the second reference to Column A should be reference to Column C.

On the next line, the reference to Column C should be to Column F.

On the next line Column E should be Column D.

On the next line Column F should be Column E.

Now turning to Schedule 5 of Exhibit 51, sheet 1, reference to Footnotes 1, 2 and 4, there is a blank after "Schedule", and in that blank should be inserted "5." Footnote 1 would read, for instance, "Exhibit 51, Schedule 5". The same correction should be made to Footnotes 2 and 4.

Now turning to Exhibit 53, Schedule 5, I need to add some exhibit numbers. That is sheet 2 of Schedule 5.

On the 12th line, which begins "Lines 5 and 6 of Columns C and D," the figure 51-J should be inserted after the word "Exhibit", and the number 52-J should be inserted on the next

[6,630]

line in the blank space.

Now turning to sheet 5 of Schedule 5, reference to the source at the bottom of the schedule on the first line, the number of 70-1 should be inserted after the words "Exhibits Numbers".

On the next line the number 71-1 should be inserted in the blank space.

With reference to the source reference of line 2 the numbers 70-1 should be inserted in the first blank and 71-1 in the second blank.

Three lines from the bottom of the page the number 72-1 should be inserted in the blank and the second line from the bottom the number 73-1 should be inserted.

On sheet 6 of Schedule 5, on the next page, on the second line in the first blank the number 72-1 should be inserted, and in the second blank 73-1.

On the fourth line insert 72-1 and on the fifth line insert 73-1.

The last page where corrections should be made is sheet 7 of 5; reference to the source, the first line, the number 70-1 and the number 71-1 should be inserted in those two spaces, respectively.

And with reference to line 3 insert the numbers 70-1 and 71-1 respectively.

There is also a numerical correction there, to the number

on line 3, Column D: The 12,802 should be 12,781. That correction does not change the results of my cost study.

That completes my corrections.

Q. Do you adopt the prepared testimony to which we have referred as your testimony in this proceeding?

A. Yes, I do.

Q. Were Exhibits 51 through 56 prepared under your direction and supervision?

A. Yes, they were.

MR. JONES: Your Honor, I move the admission of Exhibits 51 through 56.

PRESIDING EXAMINER: They will be received.

* * * *

[6,637]

* * * *

At the top of transcript page 5934 your response is in the affirmative, that there are literally hundreds of methods or permutations of methods which could be used to allocate the joint costs, in lieu of the modified Btu method and the relative cost method.

Were you exaggerating, or are there "literally hundreds of methods"?

A. There literally are. Five or six years ago I prepared a schedule showing a matrix of allocation methods, which I am showing you. And you have a choice of so many different components on this matrix that there are literally hundreds of combinations which can be made up from such a cost allocation matrix.

Q. My question to you is: Do you regard each of them as an appropriate method?

A. I have not so stated.

Q. That is why I asked you.

A. Certainly there are other appropriate methods than the ones I have used.

Q. Are there literally hundreds of appropriate methods?

A. I would not be surprised; yes.

Q. I don't know whether you were surprised or not. I am asking you whether there are literally hundreds of

[6,638]

methods, each of which you would regard as appropriate for allocating joint costs.

A. It depends on how you define "appropriate". Certainly there are a large number of economic factors which could be appropriately applied.

Q. I am using it in the sense of appropriate for the Commission in fixing just and reasonable rates.

A. Yes. There are a very large number of methods and a large number that would be appropriate. It is an extremely complicated area, this cost business. There are just a wide variation of costs that can be obtained from all of this myriad of methods, which could be appropriately applied to the production costs.

Q. Name 10 of them, each of which you would regard as appropriate as the modified Btu method and the relative cost method.

A. I will name 10 methods. There are various ways that these 10 methods can be applied.

Use a Btu basis. This could be one to one, two to one, almost any number of Btu methods, used for weighting Btu's of oil compared with Btu's of gas.

You can use a volumetric basis. This can be one to one, six to one, sixty to one, depending on what the cost occurrence is.

You can use a reservoir space method. This has been

presented before the Commission.

You can use relative cost. And you can use relative cost a number of ways.

You can use sales realization, or cost imputation, or the reserves added realization method.

You can use successful wells, gross producing leaseholds, or the by-product method.

How many do we have? I believe that is ten.

Q. It is ten, all right.

PRESIDING EXAMINER: Who or what determines which method is more appropriate than another?

THE WITNESS: It is a very difficult question, Mr. Examiner. It is the relationship of the cost incurrence which must establish this proper relationship.

PRESIDING EXAMINER: You mean different purposes require different methods?

THE WITNESS: Not different purposes; the manner in which costs are incurred in the production of oil and gas.

Accountants generally do not weight two products. For instance, if they decide to choose a volumetric method they would cost an Mcf of condensate, which is a liquid in its state out of the reservoir, the same way as they would cost an Mcf of gas produced from the same reservoir.

PRESIDING EXAMINER: But different methods produce different results, don't they?

[6,640]

THE WITNESS: Different methods produce a wide range of results; yes, sir.

PRESIDING EXAMINER: Is there any such thing as picking the correct one?

THE WITNESS: I can not see how one can just pick a number.

The approach that I propose to my clients, UDC, United Distribution Companies, is that I present a range of costs following pretty much Commissioner Carver's method that he described in his dissent, which is a range of costs.

PRESIDING EXAMINER: If you propose to use one method and Mr. Goldberg's client uses another method, is it up to the Commission to determine which is the correct method? Or can they, or would they, choose a third method, and decide neither is correct? How does it operate?

THE WITNESS: I am not a rate or return expert. But I would recommend that cost be only one of the elements that the Commission consider in deciding the price. In other words, I don't think that cost should be relied on one hundred percent for determining price.

So as long as that price is somewhere within this range of costs it is supportable, even though it cannot be decided precisely.

PRESIDING EXAMINER: You mean any result that is arrived at from A to Izzard is correct?

[6,641]

THE WITNESS: Not quite. I testified earlier that the upper range is preferable and more closely related to cost incurrence. However, within that upper range I can not give you a precise figure. It is an imprecise science.

PRESIDING EXAMINER: You are saying that the upper range is preferable from the point of view of your client.

THE WITNESS: No. I am saying it is preferable from the point of view of cost incurrence.

PRESIDING EXAMINER: Would Mr. Goldberg's client agree with that?

THE WITNESS: I don't know.

MR. GOLDBERG: I doubt it.

PRESIDING EXAMINER: I guess that is what makes ball games.

Go ahead, Mr. Goldberg.

BY MR. GOLDBERG:

Q. Among the methods you mentioned was sales realization. Has that been presented to the Commission?

* * * *

[6,679]

* * * *

REDIRECT EXAMINATION

BY MR. JONES:

Q. Mr. Larson, please direct your attention to Exhibit 52. There you show an economic factor of 2.34. Yesterday you were asked a question, if you assumed a wellhead price of 61 cents, and an economic factor of 2.34, what would be the cost of a barrel of oil.

Do you recall that line of questioning?

A. Yes.

Q. First, have you recommended a wellhead price of 61 cents?

A. No, I have not.

Q. Did you use a price of 61 cents in deriving the 2.34 factor?

A. No. I did not. I used a price of 26 cents per Mcf.

Q. That 2.34 factor, you say, is based on a wellhead price of 26 cents?

A. Yes.

Q. What price oil is that related to?

A. $3.10 per barrel, which was the average price in

[6,680]

1969, the test year that I used in my exhibit.

Q. You were asked questions about using the 1962 data for making rates in this proceeding. Do you think all of the information submitted in your exhibits will be useful to the Commission in ultimately deciding rates?

A. Yes. I think it can be used in some way. I just don't know how much weight will be put on the different costs that I present.

Q. Do you mean that you do not think that these costs should be translated into rates? I think "translated is the word I want.

A. I think the costs can be used as a guide, but should not be relied on completely in rate design.

Q. Mr. Goldberg asked you whether you had submitted evidence in the earlier phase of this proceeding, in Docket AR61-2. And I believe you said you had.

A. That is correct.

Q. In what other independent producer cases have you submitted evidence?

A. I have submitted evidence in Docket AR64-2, in Docket No. AR64-1, and Docket No. AR67-1.

Q. Did you present evidence in some individual company producer cases, prior to that?

A. Prior to that I was in about a dozen individual company proceedings.

Q. In this period that you have engaged in presenting evidence in these producer cases has the Commission changed its approach from time to time on anything?

A. Yes. We have been engaged in an experimental area of costing, and the Commission has changed its approach.

There was an attempt to be consistent from case to case, after the area proceedings started, starting first with the use of Opinion 338, then Opinion 468. But prior to that time there was a great deal of experimenting.

Q. I believe you testified yesterday that you had presented Exhibits 114 and 115 in the AR61-2 earlier proceedings. Is that correct?

A. That is correct.

Q. Did they use a particular opinion as a format, as a starting point, at that time?

A. Yes. I used Opinion 338 as the format for my Exhibit 115.

Q. I believe you testified in answer to Mr. Goldberg's question that you do not now think that is an appropriate approach. Is that correct?

A. That is correct.

* * * *

[6,682]

* * * *

PRESIDING EXAMINER: Let's be more definite than that.

MR. GOLDBERG: It is leading, to begin with.

BY MR. JONES:

Q. Has your cost evidence in each of these cases followed the same format?

A. Yes. Prior to this I have attempted to be consistent from case to case.

Q. Have you been satisfied with results?

A. I am not satisfied with the results, no.

Q. Do you think the approach you have used in this proceeding is the proper approach?

A. That is correct.

* * * *

[6,692]

TESTIMONY OF W. P. ANDERSON

* * * *

W. P. ANDERSON

was called as a witness and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. FLOOD:

Q. Would you please state your name and address for the record?

A. W. P. Anderson. My business address is 3000 Bissonnett, Houston, Texas.

Q. What is your position or occupation?

A. Vice president of Regulatory Affairs for Panhandle Eastern.

Q. Mr. Anderson, I hand you a copy of transcript Volume 48, Part 2 of 2, and direct your attention to the testimony appearing on 6394, and ask you if that is your prepared direct testimony in this proceeding.

A. It is.

Q. Do you adopt that as your testimony in this proceed-

[6,693]

ing?

A. I do.

Q. Do you have any corrections to that testimony?

A. I do not have.

Q. Mr. Anderson, I hand you a copy of an exhibit that has been previously identified as Exhibit 85 for identification and ask you if you can identify it, sir?

A. Yes, sir. That is an exhibit I had prepared.

Q. Do you adopt that exhibit as part of your presentation in this proceeding, sir?

A. I do.

MR. FLOOD: With that, Your Honor, I offer Exhibit 85 for identification as Exhibit 85 in this proceeding, and with your permission will furnish two copies to the reporter.

MR. GILLIAM: Mr. Examiner, we object to the admission of the exhibit. I move to strike the prepared direct testimony on two grounds—

PRESIDING EXAMINER: Mr. Gilliam, I want to point out something. I directed in my order setting this down that all motions to strike testimony or exhibits should be filed at least five days before we got to hearing. I do not intend to shoot from the hip on those motions to strike. I put this for the purpose of considering it before I ever got in here. You have had this testimony and had the exhibit timely enough.

MR. GILLIAM: Let me state the objection, then, to the

exhibit without regard to striking it.

The purpose of this testimony according to the witness, and purpose of the exhibit, is to support an offer of settlement which under Section 1.18(e) of the Commission's rules is still today an unaccepted offer, and it is privileged under the Commission rules.

The second reason for objection is that this particular testimony goes to a question of a charge for the haul of liquefiable hydrocarbons and liquids which the Commission has undertaken to consider in a rulemaking Docket R-338 proceeding, which is still pending. At an early point in the proceeding the Commission denied a motion

filed by the New York Public Service Commission to consolidated that docket with this docket.

So our objection to the offer is based on those two grounds.

MR. MATTINGLY: Mr. Examiner, I would like to say one thing concerning the remarks Mr. Gilliam made.

One, I believe he said this settlement proposal is privileged. I don't know just what he means by that term. The settlement is a public document on file with the Commission, and has been incorporated in those proceedings. I did not see how that would affect the admissibility of this.

I do not understand what the fact that there is a pending rulemaking in R-338 has to do with it.

[6,695]

PRESIDING EXAMINER: What is the purpose?

MR. FLOOD: To provide a basis for the cost per Mcf of hauling gas from offshore. It is in connection with the prices which have been used in the settlement which has been filed in this proceeding. But it does provide definitive support, in our view, for that.

PRESIDING EXAMINER: Would there be testimony by Mr. Anderson, or would that exhibit be offered if there had been no settlement proposal?

MR. FLOOD: Your Honor, that is difficult to answer.

I think there may very well have been a relevant question as to an appropriate charge for hauling gas from offshore, as related to the area ceiling price. And I believe, while I did not cross that bridge, that it would have been offered, yes. That issue was raised in Opinion 546 and left unanswered.

This testimony goes to the unanswered question in 546.

PRESIDING EXAMINER: What is the unanswered question?

MR. FLOOD: The appropriate charge for hauling liquefiables and liquids onshore. I don't recall the page number, but I will be happy to provide it to you.

So it is relevant to the Commission's opinion as affirmed and returned to the Commission for reconsideration here.

MR. MATTINGLY: Mr. Examiner, may I say one more thing in response to the order of the Commission on the 24th that it incorporate this settlement? I want to state on the record

[6,696]

the Staff's position that any evidence in support of or in opposition to the settlement is highly relevant in this proceeding, and we feel very strongly should be admitted in.

PRESIDING EXAMINER: Mr. Gilliam?

MR. GILLIAM: I want to say in response to Mr. Flood with respect to the issue of the charge for the haul, that is the precise issue that the Commission has pending in another proceeding, the rulemaking proceeding in R-338. And the Commission did at a prior point deny a motion to consolidate that issue into this case.

So it would seem that, absent the question of supporting a settlement, that particular issue is already in another proceeding before the Commission.

PRESIDING EXAMINER: You put me in a difficult position.

I can not see that the settlement proposal itself has any relevance in this hearing, in and of itself. However, I do not want to preclude the Commission from access to information which it may use in the promulgation of the settlement proposal.

Ordinarily I would exclude the exhibit and the testimony, since they bear on figures which are in the settle-

ment proposal. But I do not, as I said, want to withhold from the Commission testimony or evidence which it might use for the purpose of considering the settlement proposal.

MR. MATTINGLY: Why would you exclude that if the

[6,697]

settlement itself is in the record, which is the case in this proceeding, Mr. Examiner? I think that is what makes a difference.

PRESIDING EXAMINER: Let us go off the record a moment.

(Discussion off the record.)

PRESIDING EXAMINER: On the record.

In the light of the Commission's order I feel that I am constrained, by the Commission's order incorporating the settlement, to admit the testimony and the exhibit, and we will have cross-examination on the evidence in the testimony and the exhibit.

(THE DOCUMENT HERETOFORE MARKED AS EXHIBIT NO. 85 WAS RECEIVED IN EVIDENCE.)

MR. FLOOD: I hereby hand the reporter two copies of Exhibit 85.

The witness is ready for cross-examination.

PRESIDING EXAMINER: All right, Mr. Gilliam.

CROSS-EXAMINATION

BY MR. GILLIAM:

Q. Mr. Anderson, my questions are on behalf of Mobil Oil Corporation, one of the respondents in this proceeding.

With reference to your study that is now Exhibit 85, when was this study prepared?

PRESIDING EXAMINER: Excuse me. Mr. Gilliam, before you get into cross-examination let us have a recess. I had not

[6,698]

noticed the time.

(Whereupon, at 11:20 a. m. a recess was taken until 11:30 a. m. of the same day.)

PRESIDING EXAMINER: On the record.

BY MR. GILLIAM:

I had asked you when this Exhibit 85 was prepared.

A. I believe our work on it started some time around the first of October. I don't have the specific date.

Q. Of 1970?

A. Right.

Q. Has this study, or a similar study prepared by you, been submitted or distributed in any other proceeding before the Commission?

A. Basically this study was distributed in an informal conference in Docket R-338.

Q. As far as you know, has the Commission acted on—in this docket?

A. I am not aware that they have.

Q. It is our understanding that this study is a national systemwide cost of transportation for the particular pipelines and does not attempt to show separately either cost or commodity miles for the Southern Louisiana area. Is that correct?

A. This encompasses the entire transmission system of these seven Southern Louisiana pipelines regardless of where

[6,699]

they go.

Q. Did you make any attempt to separate either costs or miles for Southern Louisiana?

A. I was unable to do this from the information available.

Q. Have you considered whether there are any differences in the costs or the characteristics of the operation of these lines within Southern Louisiana as compared to their systemwide operations?

A. There are some differences, I am sure, but I have not made a detailed study of what they might be. Some might involve higher-cost projects, offshore for example.

Q. Did you make any effort to make that determination prior to preparing this particular study?

A. We have looked at some of these. We have found it an extremely difficult matter to obtain the raw data to do this type of study.

Q. The next question may more properly go to Mr. Moye, but I will ask you.

MR. GILLIAM: We asked for the diameter size of the pipe that had been considered in these studies. Last night we were served with work papers that included some of your work papers and some of Mr. Moye's. I wondered if counsel could state the present status of intimation as to the size of pipe for the lines Mr. Anderson considered.

[6,700]

MR. FLOOD: Is this a question to me or to the witness?

MR. GILLIAM: Well, we were not certain which of the two witnesses would be responsible for questions as to the diameter of pipe.

THE WITNESS: Let me answer as to the seven companies listed in this study. This is the transmission system of those companies, and encompasses whatever properties they have classified in their system of accounts, in their accounts according to the System of Accounts, as transmission properties. This may range from 16 inch to 36 inch pipe. I have no way of telling. It encompasses the entire range of size of pipe.

BY MR. GILLIAM:

Q. Did you make any effort to determine whether there was any difference in the size of pipe for these lines in Southern Louisiana as compared to the rest of their systems?

A. No, I did not. As to the transmission facilities, they would probably be approximately the same as in other States, other places along the pipeline.

Q. Mr. Anderson, in your work on cost accounting have you found that the size of pipe has any connection with cost incurrence?

A. Yes; certainly. The bigger the pipe the more dollars.

Does that answer the question?

Q. How about in the cost of operation?

A. Generally speaking, I expect there would be some

economics of scale.

PRESIDING EXAMINER: You mean it would cost more or less?

THE WITNESS: Cost less.

PRESIDING EXAMINER: To operate a large pipeline than a small pipeline?

THE WITNESS: I believe that would be true. I think that is more properly directed to an engineer. But it would be my impression.

BY MR. GILLIAM:

Q. A 36-inch line, compared to a 12-inch line, would permit economies of scale in operation, is that correct?

A. I believe that is true.

Q. Turning to Exhibit 85, how did you select these particular pipelines?

A. We made a survey of those companies who operate out of the South Louisiana area who have recent rate filings and from whom the data were available.

As you are aware, there are certain South Louisiana pipeline companies who are not in this tabulation, and the reason for that is purely that the data were not available, either by contacting them or from their rate filings.

Q. We noted the omission of Michigan Wisconsin, United, and Transcontinental, all of whom have systems in Southern Louisiana. Did you ask those companies to supply data to you?

A. We contacted those companies and they did not have

the data available to furnish us.

Q. Do you know the relative age of the systems, say United, compared to the age of the systems you used in this study?

A. United is relatively old. Transco and Mich-Wis are comparatively relatively young.

Q. Do you have any understanding of the relative size of the United cost as compared to the figures you used for the seven companies in your study?

A. No. United's system is so complicated it is nearly impossible to tell whether they are transporting gas for

themselves or someone else, or backhauling, or what. It is very difficult to get figures on United.

Q. Is it not correct some of the companies you have used also haul gas for others?

A. Yes. They do.

Q. Which of those on this list of seven, as far as you know?

A. Tennessee, Texas Eastern, Texas Gas; Columbia Gulf, of course.

Q. For the record would you state generally, going down the list of the seven companies, the location of the systems that you have considered, taking first Columbia Gulf?

A. Columbia Gulf runs from Rayne Field to I believe somewhere in Kentucky.

[6,703]

Q. The next is Natural Gas Pipeline Company.

A. That runs from—this includes both their East and West systems, the old Texas-Illinois system. The Texas Illinois or Gulf Coast system comes out of the Gulf Coast, to the Chicago area.

The other section, the Western Section, comes out of the Hugoton Anadarko field and runs to the Chicago area, basically.

Q. Are the costs of that pipeline as you just described included in the figures that appear on line 2 of Exhibit 85?

A. Natural Gas Pipe is all-inclusive of both systems, Gulf Coast and Hugoton Anadarko.

Q. The next, for general location, is Southern Natural.

A. From Southern Louisiana to Georgia.

Tennessee, to the East Coast from Southern Louisiana.

Texas Eastern from the East Coast to Pennsylvania and the New York area.

Texas Gas from Southern Louisiana to, basically, the Ohio Valley, the Ohio River Valley.

Trunkline from Southern Louisiana area and Texas Gulf Coast to the Detroit area.

Q. Mr. Anderson, did you send these companies a questionnaire or simply ask them for certain data? What instructions did you give them?

A. Most of this data comes directly from their rate filings. All of page 2 of my exhibit is directly from their

rate filings.

On page 3, we were able to obtain the mileage, commodity mileage factor on three of the companies directly from their rate filings. And they furnished us the information on the other four companies.

Q. Did you or persons under your supervision select this information from their rate filings?

A. Yes, sir.

Q. Do you have—

A. It is quite standard information in all of these rate filings.

Q. Do you have with you your work papers?

A. Yes.

Q. I had some specific questions dealing with Natural Gas Pipe of America, Southern Natural, and Tennessee.

A. Right.

Q. We had asked in a letter for a breakout from operating expenses as you have listed them, the expenses associated with compression for these systemwide pipelines.

In Examining the work papers last night our people noticed on Natural Gas Pipe of America, Statement I, page 8 of 11, certain lines that we feel reflect directly for that pipeline the expenses associated with compres-

sion. I wondered if you could read off from Column 1 of that work paper into the record the particular expenses shown there that are associated

[6,705]

directly with compression.

A. Yes, sir.

Line 3, compressor station labor and expense, the labor element is $4,621,008. The other cost is $1,475,836. Gas for compressor station fuel, $9,128,901.

On lines 18 and 19, maintenance of compressor station equipment, labor is $2,337,869. Other expenses, $3,561,-028.

Those are the costs out of this 193 million dollar total cost which can be identified as compressor.

Q. I direct your attention to line 8, that is transmission and compression of gas by others, as a cost item. Should that be included?

A. I don't know how much is compression and how much is transmission.

Q. Well, Mr. Anderson, would it be correct in interpreting your exhibit that the figures you just read off are included on Exhibit 85, page 2, line 2, in the $48,-863,600 operating expense?

A. Yes, sir. They are.

Q. According to our rough check, and I ask you to accept it subject to check, the items you have tabulated come to approximately 40 percent of the total operating expenses there shown. I think, though, the figures involved are all in the record for that line.

Let me take Southern Natural.

MR. FLOOD: In the 40 percent did you include the three million-three on the transmission and compression of gas?

MR. GILLIAM: I knocked it out. With it, it came up to approximately 50 percent.

THE WITNESS: I have not made that tabulation. I will accept your figures for that purpose.

BY MR. GILLIAM:

Q. Turning to the sheet on Southern Natural, Schedule J-1, sheet 4 of 5, similarly has set out what we believe are some direct expenses attributable to compression.

A. Yes, sir.

Q. Could you go down that list and read into the record the ones you would identify on Southern Natural as being directly attributable to compression?

A. The compressor station labor is $3,400,000. Compressor station supplies and expenses $422,000. Compressor station fuel $5,650,000.

Under the maintenance classification, compressor station equipment, labor $598,000; compressor station equipment, supplies and expenses $862,000.

Those are the only costs which can be directly related to compressor. Obviously, in the rest of these costs there is no depreciation figure which can be broken out, there is no return figure, there is no property tax figure. All those costs have some relation to compressor station, but we can

not break them out from the data available.

Q. Going back to make sure we have compared it correctly, on Exhibit 85, page 2, with respect to Southern

Natural, our rough calculation was that the figures you have identified are approximately 30 to 33 percent of the total operating expenses shown there.

Have you made that kind of calculation?

A. I have not.

Q. Let's go to your work paper on Tennessee Gas—excuse me a minute.

Let's go to Texas Gas Transmission. Do you have Statement I?

A. Yes.

Q. Could you identify the compression expenses listed there, just for the record, if you will?

A. Transmission compressor fuel $5,794,000, compressor supplies and expenses $744,000, compressor engine maintenance $1,861,000.

Those appear to be the transmission compressor expenses which are included.

Q. I assume you made no computation of what percent those are of the total operating expenses you listed in Exhibit 85.

A. I did not.

Q. In checking your work papers those are the only

three pipelines we found we could specifically identify operating expenses for. I mean compression component of operating expenses.

Could you make a quick check of your other work papers that you have there to see if any of the other pipelines of the seven have set out items for operating expenses attributable to compression, that you could put into the record now?

A. I have the same working papers that you have, so I accept that if you made the check, that is it.

Q. Do you know the figures for any of the others, other than the three we just discussed?

A. I do not; no, sir.

Q. Do you know as to whether that breakout could be supplied for the record at a later date for the other four pipelines listed? Perhaps that is a question for your counsel.

MR. FLOOD: It is my understanding that it can not, Mr. Gilliam, that the breakout here is the breakout available to the witness.

BY MR. GILLIAM:

Q. Let me ask the same question—perhaps also this should go to counsel—as to whether a breakout of investment attributable to compression could be obtained for any of the lines shown in the study.

MR. FLOOD: I think you can direct that to the witness. He is an expert in that area. He can tell you.

THE WITNESS: The system of accounts under which we all operate provides certain accounts which would show the investment in the compressor station equipment.

What happens in these cases is that we all take the base period, which ends at some date, and we would show the compressor station equipment as of that date. But then any adjustments which are made to that plant are made by functional groups, not by particular accounts. So the actual base period figures are not necessarily those on which the rate case is based.

Add to that the fact that no company of which I know keeps their reserve for depreciation by particular accounts. Therefore, there is no way to obtain reserve for depreciation for the compressor station equipment by itself.

BY MR. GILLIAM:

Q. Have you asked any of these lines for a special study to break this out?

A. I have not. This has not been the thrust of my testimony.

Q. To make sure the record is clear, Mr. Anderson, the operating expenses that we have been discussing, and those compression expenses, relate to every compressor on each system? Take Tennessee, going into New York or New England.

A. It does not relate to their booster compression in the field, nor to their storage compressors.

[6,710]

Q. Have you made any study of how much compression is supplied by pipelines to producers on systems that transport liquefiable hydrocarbons or liquids from offshore to onshore?

A. I have not.

Q. Do you know an answer to that question, at all? Is it generally provided?

Do you have any knowledge of what percent of the compression expenses that we have been discussing on any of these lines would be attributable to the operation of compressors in the offshore Louisiana area?

A. I have no feeling for that at all.

Q. Would your answer be the same if I broadened the question to the Southern Louisiana area?

A. I would have no idea as to how much compression is done in the regional location of the Southern Louisiana territory.

Q. One of our questions in connection with the work papers was the rate of return requested by these seven pipelines in the rate dockets.

We found in your work papers a notation of that. I might speed this up if I just read to you the figures we found and ask you to state whether they are correct.

A. Yes, sir.

Q. Columbia Gulf, 8.25 percent.

A. Yes.

Q. Natural Gas Pipeline Company 8.75 percent.

A. Yes.

Q. Southern, 9 percent?

A. Yes.

Q. Tennessee, 9 percent?

A. Yes, sir.

Q. Texas Eastern, 8.625 percent?

A. Yes, sir.

Q. Texas Gas, 8.5 percent?

A. Yes, sir.

Q. Trunkline 7.39 percent?

A. Yes, sir.

Q. As we understand your work papers those are the rates of return that have been sought in the rate dockets identified.

A. That is right.

Q. Do you know whether the Commission has allowed those particular rates of return?

A. In many of these dockets there has been no decision at all.

Q. So in your—

A. Some of them have not even gone under suspension as of this date.

Q. So Exhibit 85, then, on page 2, the amount that is shown for return is taken simply from the rate filing and not

[6,712]

from an allowance by the Commission, is that correct?

A. That is correct.

Q. Have you made any computation as to what would be reflected in that column if the Commission, for example, reduced any of these rates of return by one percent?

A. I will take it the other way: If we were to put all of these companies on a 9 percent rate of return, and that is raising five of the seven companies, the unit cost would be 2.13 cents rather than 2.08 cents.

Q. Let me ask the other question: Suppose they came down one percent?

A. All right. Let me go at it this way: We have raised the cost here about 30 million dollars in the total cost of service, by going up this amount. Thirty million dollars equates to about 5/100ths of a cent.

Q. I am not sure that I understand the answer. Is it your answer that if it were reduced one percent it would reduce—what figure?

A. Let me put it this way: If we reduced that by 30 million dollars the end result, cost per mile of 2.08 cents, would be reduced by approximately 5/100ths of a cent.

Q. And that answer is based on a reduction of one percent?

A. That answer is based on a reduction in this total cost of service of 30 million dollars.

[6,713]

Q. Have you made a computation as to the reduction in the amounts shown for Federal income taxes that would also follow from such a reduction?

A. That is included in this figure that I have been discussing. That is return and taxes.

Q. Do you know whether any of the other items that are included in the transmission cost that you show on page 2—

Let me withdraw that.

Has the Commission passed on any of the other items, such as operating expense, depreciation expense, and so on, that you show on page 2, in these rate cases?

A. They have in some instances, yes.

Q. Do you know whether any of these items are still subject to question by either the Commission Staff or parties in those rate cases?

A. Oh, certainly in all of these cases that are still open the whole issue, the whole transmission cost of service, is still open.

Q. Including depreciation expense?

A. Yes.

Q. Does it include questions as to depreciation rate?

A. Yes, it would. Tennessee and Southern have requests in for increase in their depreciation rate.

Q. Are those contested issues in those cases?

A. You bet.

[6,714-6,715]

Q. Could you direct your attention to the column headed "Revenue Credit"?

A. Yes, sir.

Q. Explain what that covers, please.

A. Generally that is—well, let me see. The big amount of Natural's 5,093,000 is for transportation for somebody else, transportation agreements, revenues of which are credited back to the transmission cost of service.

Shall I go on with these others?

Q. Yes. Would you take, say, Southern and Trunkline?

A. Southern's, a lot of miscellaneous items, the largest of which is $752,000 which relates to—they have classified it as "Other Gas Revenues". I can not tell you more specifically than that what it is. Apparently there is no transportation in that figure. They have some rent, some incidental gasoline and oil sales.

In the case of Trunkline it is transportation of gas for others.

Q. Could you shift your attention to the column "Allocated Other Functions"?

A. Yes, sir.

Q. And will you explain what that is?

A. In the case of Tennessee and Texas Eastern certain of their transmission costs are accumulated in one fashion, and in order to get a pure transmission cost they have to allocate

these costs to other functions.

Basically in the case of Tennessee the 12 million dollars is the cost which is allocated to the operation and investment in their New England laterals.

In the case of Texas Eastern that is costs which have been accumulated under the transmission cost classification, which have been allocated to production. Their Zone A—which I cannot tell you more than about that—Texas, and to their storage functions.

Q. Could you direct your attention now to page 3 of Exhibit 85? And would you state how that particular Mcf per mile was computed? Actually, I am asking for some clarification of your testimony on this. If you want to look at that first, also, fine.

MR. FLOOD: What page, counsel, are you referring to?

MR. GILLIAM: Page 3 of 85.

MR. FLOOD: But what page in the testimony?

MR. GILLIAM: He refers to this on page 4. He refers to it again on page 5. But there was not a narrative explanation of how this particular computation was made.

THE WITNESS: Commodity miles are a fairly standard method, quite-often-used method of allocation in the gas pipeline business. It means no more than that you take the number of miles you haul each Mcf of gas and multiply it by the number of Mcf you are hauling. For example, if you are hauling

[6,717]

from South Louisiana to Detroit you multiply the number of Mcf that you are delivering in Detroit by the mileage to Detroit. That gives you your commodity miles.

It obviously weights for where you make your main deliveries and where you drop off gas along the line. It is purely a computation much similar to what is known as passenger miles in the airline industry.

MR. GILIAM: Your Honor, may I have one minute in which to check?

BY MR. GILLIAM:

Q. Mr. Anderson, have you made any study of the costs that you show here, using the rates of these particular pipelines prior to the rate filings that you reflect in Exhibit 85?

A. That information I did not have available. No, sir I did not do it.

The rate filings provide the only real source of getting a functionalized transmission cost of service, which is page 2 of this exhibit.

Q. For example, on Texas Eastern you did not go back to the docket that preceded RP70-29?

A. No, I did not. This is the most recent information that I had available at the time.

Q. I have one last question, just to make certain that if we made a computation you would agree. We did not find

[6,718]

in your work papers figures that were for rate base as such.

We have the rate of return figure. We have the resulting return figures. How would you work back to get the rate base?

A. The return figure shown here, divided by the rate of return used, which you read into the record, would give you your rate base for the transmission function.

Q. When you use the term "transmission function" in that answer, would you define that?

A. Transmission as defined by the Uniform System of Accounts, which is transmission from the end of the gathering system to the market.

Q. Which in this instance, in your figures, includes compression?

A. Yes, sir. It certainly does.

MR. GILLIAM: Thank you. That is all I have.

* * * *

[6,725]

* * * *

PRESIDING EXAMINER: Generally speaking, would you say the cost of construction of a pipeline offshore is more expensive than cost of constructing a pipeline on-shore?

THE WITNESS: Yes, from my experience; yes.

MR. MORING: That is all I have.

* * * *

[6,734]

TESTIMONY OF JOHN L. MOYE

* * * *

JOHN L. MOYE

took the stand, and having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. FLOOD:

Q. Would you please state your full name and address for the record?

A. John L. Moye, Post Office Box 2511, Houston, Texas.

[6,735]

Q. What is your occupation, Mr. Moye?

A. I am director of planning for Tennessee Gas Transmission Company.

Q. I show you Volume 38, Part 2 of 2, specifically pages 6400 through 6408, and ask you if that is your direct testimony in this proceeding.

A. Yes, it is.

Q. Do you adopt that as your testimony in this proceeding, sir?

A. I do.

Q. I show you exhibits previously identified as Exhibits 86, 87, and 88, Mr. Moye, and ask you if you can identify those exhibits.

A. Yes, I can.

Q. Were those exhibits prepared by you or under your supervision and direction?

A. They were.

Q. Do you adopt those exhibits as part of your presentation in this case?

A. Yes.

MR. FLOOD: Your Honor, at this time I would like to offer Exhibits for identification 86, 87 and 88 in evidence as Exhibits 86, 87 and 88, and tender the witness for cross examination.

MR. GILLIAM: Your Honor, without burdening the record,

[6,736]

we object to those exhibits on the same grounds as we expressed earlier this morning with respect to the witness Anderson's exhibit.

PRESIDING EXAMINER: And with the same comments I made with respect to the other exhibits, I will admit them into the record.

(THE DOCUMENTS REFERRED TO, MARKED EXHIBITS 86 THROUGH 88 FOR IDENTIFICATION, WERE RECEIVED IN EVIDENCE.)

MR. FLOOD: With the Examiner's permission I would like to provide two copies of these exhibits to the reporter for inclusion in the record. The witness is tendered for cross examination.

PRESIDING EXAMINER: Who is going to cross examine?

CROSS EXAMINATION

BY MR. GILLIAM:

Q. Would you turn to page 5 of your prepared testimony, Mr. Moye, the sheet on which you have a formula?

A. Yes.

Q. As we understand your testimony, the figure of 2.0 cents per Mcf appearing in the middle of that formula is obtained from Mr. Anderson.

A. I did use Mr. Anderson's 2.0 cents.

Q. If that figure were changed to 1.5 cents, for example, what effect would that have on your 20 cents per barrel figure?

A. The effect would be a reduction in the 20 cents per barrel.

Q. In the 20 cents per barrel figure?

A. Yes.

Q. It would simply be a process of mathematics to compute it, is that correct?

A. That is correct.

Q. In the same formula you use 100 miles as distance hauled. If that, for example, were changed to 60 miles what effect would that have?

A. The change to 60 miles, if it is presumed—well, the 20 cents is for 100 miles; and it would reduce the 20 cents.

However, the cost per barrel in two-phase systems is not really susceptible to a mileage charge in the same sense as hauling gas is.

Q. This is for reasons that you have stated at page 3 of your testimony?

A. That is correct.

Q. In your testimony you refer to two-phase systems. Would you state for the record the particular systems to which you are referring in this testimony?

A. The two systems are both operated by Tennessee Gas Pipeline. They are what is referred to as our Cameron system, and our 30-Inch Header system, that comes into

main line valve 523.

Q. Do you have your workpapers handy?

A. Yes.

Q. Do you have one sheet showing a page headed "Cameron System?"

A. Yes.

Q. As we interpret that workpaper on the Cameron system the average haul is 34.2 miles. Is that a correct interpretation?

A. Yes.

Q. That is one of the two systems you considered?

A. That is correct.

Q. Your workpaper had a similar sheet headed "Ship Shoal." Is that the other system you described?

A. Yes.

Q. As we interpret that sheet you had, at least in June 1970, an average haul of 60.6 miles on that system.

A. No. On that system the average haul was 104.38 miles.

Q. So the 60.6 is a composite?

A. Of the two systems, yes.

Q. Under your proposal here would a producer whose liquids are carried only in the Cameron system be required to pay based on your composite formula?

A. That is correct.

[6,739]

Q. So you would not distinguish, for example, in your proposal between the actual miles identifiable for a given producer?

A. That is correct.

Q. In the operation of these systems, Mr. Moye, as an accounting or operating matter, do you record the point of input for a given producer and the point where that quantity attributable to his interest is taken out of the system?

A. Any gas purchase has a meter identified with it, a purchase meter. This would be the point of entry.

As far as a point of exit, in this instance we are talking about barrels, it would be at a separation facility.

Q. Take the Cameron system, if Producer X put liquids in that system, you hauled them, then they were taken out, your normal routine accounting would record those facts, would it not?

A. I do not believe Tennessee Gas Pipeline's routine accounting would.

Q. How would you keep records of this transaction which I just possibly oversimplified?

A. On this particular system the plan is operated by Continental. They are the plant operator, and I am sure their records reflect a separation and allocation of these liquids to the producer.

Q. Your records, in turn, would record the input into your system?

A. Not of the liquids; of the gas only.

Q. Continental's records would have both?

A. I certainly believe they would. I do not know that of my own knowledge.

MR. GOLDBERG: Mr. Examiner, I wonder, with respect to these questions, whether this is the witness, even with respect to Tennessee. I don't see in his qualification that he really knows anything about their accounting.

PRESIDING EXAMINER: Are you familiar with the accounting practices of Tennessee Gas Pipeline?

THE WITNESS: No, sir. I am not in the accounting department, and I do not think, as a general rule, that I could say I am familiar with that.

BY MR. GILLIAM:

Q. Are you familiar with the operating practices on this system?

A. Generally yes.

Q. Such as where meters are located?

A. I cannot give you specific locations. They are located on platforms. But when you require a specific platform identification for a certain producer, no. I don't have that information with me. I know where it is available.

[6,741]

Q. As a general practice are you familiar with where the gas coming into a system such as Cameron is measured and where the gas going out of the system is measured?

A. Yes.

Q. Thank you. Mr. Anderson used as a sample in his Exhibit 85 seven pipelines. Do you have any figures as to average haul per mile for any of those pipelines today, other than the two systems we have previously discussed?

A. I did not understand the question as related to Mr. Anderson's testimony

Q. He lists seven pipelines, and he uses those seven pipelines to arrive at a transmission cost of service.

Do you have any figures as to the average haul for those seven pipelines, with the exception of the two systems of your own that we have discussed?

MR. SHIBLEY: By "average haul" do you mean distance?

MR. GILLIAM: Distance.

THE WITNESS: No, I do not have it.

BY MR. GILLIAM:

Q. On the two systems that you have considered, that we have discussed, what was the load factor during the period you considered?

A. May I ask you to define "load factor?" In my mind it is not readily applicable to a gathering system, in the usual sense that we consider "load factor."

[6,742]

Q. Let me put it this way: In the sense of having a fixed capacity in one of these systems, and the use of that capacity during a given period.

Your workpapers are based on June 1970.

A. Within the gathering system—the capacity any pipeline has in a gathering system is dependent on the pressure at each end.

All of these offshore gathering lines operate at the pressure available; they are at capacity at that pressure. If the pressure conditions can be changed there is a different capacity.

And generally these were operated at what we might term—when you look at pressure drop per mile, that may be some indication of what you are terming "load factor," or operating at capacity. These operate over the full range of from 1 to 2 psi per mile pressure drop, up to 18 pounds per mile pressure drop, and that is certainly a well loaded system.

Q. By "these" in that answer to which lines are you referring?

A. I am referring here to the Cameron system.

Q. Will you turn to your formula on page 5 of your prepared testimony?

A. Yes, sir.

Q. What assumptions did you make there as to the use

[6,743]

of capacity?

A. There is no assumption in that formula as to use of capacity. It is based on the premise that all the capacity is used.

Q. 100 percent?

A. Yes; and because of the movement of free liquids in the pipeline the capacity is reduced a given amount.

Q. If you had this assumed pipeline that you show here with capacity of 100,000 Mcf per day, and it in fact was operating at 60,000 Mcf per day, what effect would that have on the operation of your formula?

A. I am not sure that I understand your question. The pipeline has a capacity within certain pressure conditions. At a given pressure condition it is operating at capacity. If the pressure can be—if the pressure differential can be increased there is another capacity associated with it.

Q. In an earlier answer you stated that this assumption was that this pipeline in your example was operated at complete use of the capacity.

A. That is correct.

Q. Assume that that same pipeline exists and is constructed and it has that operating capacity, but in fact instead of 100,000 Mcf per day going through it only 60,000 Mcf per day is going through it. We are assuming the same

line as you have in your example.

What effect does that use at 60,000 Mcf per day instead of at 100,000 Mcf per day have on the operation of the formula on page 5?

A. The formula is based on a percent reduction in capacity when a pipeline is operating at velocity greater than 10 feet per second. If in your hypothetical case the pipeline is operating at greater than 10 feet per second it would have no effect.

Q. In your testimony at page 7 you make reference to a cents per Mcf figure on underground storage costs. Is this figure a system-wide figure for Tennessee?

A. That is system-wide for the four underground storage fields operated by Tennessee.

Q. Where are they?

A. In the States of Pennsylvania and New York.

Q. There are none in Southern Louisiana?

A. That is correct.

Q. Your formula where you use the 100 miles—this is the formula on page 5—did you derive that from Mr. Anderson?

A. No.

Q. What is the origin of that figure?

A. Of the formula?

Q. The use of 100 miles as distance hauled, in the

formula.

A. The 100 miles was derived from knowledge of the average haul existing today on Tennessee's system and what other pipelines are doing; and also by looking at the recent lease sale, that I believe was December 15, 1970.

I have estimated that the average haul from these leases, if they are all considered productive, would be slightly in excess of 100 miles.

As new reserves are added offshore I do believe the average haul will be more than today.

Q. When you say "recent lease sale" you are referring to a lease sale offshore Louisiana in December 1970?

A. Yes, sir.

Q. We note in one of your workpapers the heading "Average Pipeline Miles to Possible Separation Facility." The average straight-line miles you show as 78 miles. Is that correct?

A. That is correct.

Q. Beyond that, again that is an estimate prepared by you, not derived in any way from Mr. Anderson's study?

A. That is correct.

Q. With respect to the Ship Shoal system that you identify in your workpaper, could you state for the record where your compression facilities are located on that system?

[6,746]

A. There are none.

Q. Take the Cameron system. Where are they located?

A. There are none.

Q. We had one question that related to the figure on page 7—657,000 annually.

Could you state what is covered by that cost, what operations?

A. That is the cost of providing underground storage in the event that the gas supply is not available from a producer that is shut down because of weather conditions, if he is barging his liquids, 10 percent of the time.

Q. Would that include an injection system?

A. What do you mean by that?

Q. For storage.

A. Yes.

Q. These figures are based on the facilities located at your storage in the northeast part of your system?

[6,747]

A. That is correct, and those facilities in that area certainly can be and would be used in such an instance.

Q. Thank you.

MR. GILLIAM: That is all we have.

* * * *

[6,763]

TESTIMONY OF LOUIS J. ENGEL

FEDERAL POWER COMMISSION
BUREAU OF NATURAL GAS

Docket Nos. AR61-2 et. al. and AR69-1

AREA RATE PROCEEDINGS
(SOUTHERN LOUISIANA AREA)

Re: Rate Design and Recommendations

Q. Please state your name, address, by whom you are employed and your present position.

A. My name is Louis J. Engel and I reside at 2979 Brinkley Road, Oxon Hill, Maryland. I am employed by the Federal Power Commission as a Supervising General Engineer in the Bureau of Natural Gas.

Q. Briefly describe your education, experience and other pertinent qualifications.

A. I was graduated from Louisiana State University with a Bachelor of Science Degree in Petroleum Engineering in 1958. Prior to graduation, I served two years in the U. S. Army Infantry. Subsequent to graduation, I was employed by Welex Inc. to assist in gas and oil well completions in the marsh land area of South Louisiana. In 1959, I accepted employment with the Federal Power Commission. During this tenure I worked on all phases of producer regulation performed by the technical staff. This includes matters concerning rate filings, certificate applications, settlement progress, individual producer rate and certificate proceedings and all area rate proceedings with the exception of the Permian Proceedings.

Q. State the proceedings in which you testified before this Commission.

A. I testified in all area rate proceedings with the exception of "Permian." I also testified in Medina Gathering Corporation, et. al.,

[6,764]

* * * *

Q. What is the purpose of your present testimony?

A. To design rates and some other related recommendations applicable to all jurisdictional sales of natural gas in Southern Louisiana including past as well as future sales.

Q. Are you familiar with the recent court decisions involving these proceedings?

A. Yes. I have carefully reviewed the decisions of the U. S. Court of Appeals for the Fifth Circuit concerning FPC Opinion Nos. 546 and 546-A. To the extent possible in preparing my rate design I have followed the recommendations of the court in an attempt to improve area ratemaking, and I will discuss the court suggested improvements during the course of my present testimony.

Q. Are there any other matters of special significance which you considered?

A. Yes. An additional matter which I view as being of primary importance is the settlement proposal filed on November 6, 1970 by the United Distribution Companies (UDC). This proposed settlement has been incorporated into the record of this proceeding. I will comment on the settlement proposal at a later point.

Q. What do you consider as the most important issue in these proceedings?

A. The maintenance of adequate gas service by the producing industry to other segments of the gas industry is without doubt the most

serious issue which must be considered. Evidence in this record clearly indicates that gas reserve additions have declined sharply in recent years in relation to production and, if allowed to continue, will result in the nation's inventory being reduced to a critical level. By year-end 1969 the reserve production ratio had declined to 13 to 1 with no sign of leveling off. The evidence in this record further indicates that natural gas demand will continue to rise (See Table 1) resulting in a still greater drain on gas inventory unless production is replaced. My own opinion is that the true demand for natural gas is at some unknown level far above that indicated in evidence because of the bargain value of gas and its clean burning qualities which will aid this nation's pollution problems.

The solution to this issue is obvious. The gas producing industry must increase its gas prospecting and discover substantial volumes of new gas reserves.

Q. Are there large volumes of proved reserves which can be made immediately available?

A. Unfortunately, the existing volumes of proved reserves available for sale are very small in relation to demand. Evidence in this record shows that in Southern Louisiana such volumes amounted to only 2.6 trillion cubic feet as of year-end 1969. Thus, the necessary new reserves will be made available only through further exploration and drilling.

Q. Where in your view will the necessary new reserves be found?

[6,766]

A. For the next several years, the primary source of new gas supplies will be the Continental United States.

Q. What about gas supplies from Canada?

A. Gas will continue to be available from Canada. However, considering the growing demand for gas in Canada the United States cannot reasonably expect to obtain more than a fraction of its requirements from Canada.

Q. What about other sources of natural gas?

A. A number of applications have been filed for authorization to import LNG into the United States from foreign countries, primarily Algeria. LNG will undoubtedly increase its contribution to the American market in future years, but it cannot be expected to make a substantial contribution to total gas requirements for some years to come. The required investment in liquefaction, transportation, transmission, storage and distribution facilities will be enormous. Evidence in this record also indicates that the cost of imported LNG will be substantially higher than prevailing price levels. Consequently, I do not think LNG can be expected to provide a solution to the current gas supply crisis.

With respect to the gasification of coal, the technology is clearly emerging, but at the present time few plants are in operation. Therefore, I do not anticipate that gas manufactured from coal will make a significant contribution to supply for at least the next several years.

[6,767]

Alaska is another potential source of gas. The apparently tremendous oil discoveries which have taken

place there should provide large volumes of casinghead gas. However, development of the Alaskan reserves must await the construction of necessary transportation facilities. Thus in all likelihood Alaskan gas will not become available in substantial quantities for several years.

Q. Are potential reserves of gas in Continental United States sufficiently large to provide for an increase in available supply?

A. Yes. The potential gas committee of the Potential Gas Agency, Mineral Resources Institute issued a report dated October, 1969 indicating that the estimated potential gas supply of the "Lower 48" to be about 795 trillion cubic feet (Tcf). Of this amount, 286 Tcf are in what is commonly referred to as the Gulf Coast. More specifically Texas Railroad Districts 2, 3, 4 and a part of 1; the area south of the 31st parallel in the state of Louisiana and the offshore areas seaward of both states. The committee further reports that of the 286 Tcf, 142 is offshore Gulf Coast and 144 onshore. In addition, of the 142 Tcf, 89 Tcf is seaward of the state of Louisiana of which 26 Tcf are classified as "Probable," 50 Tcf "Possible" and 13 Tcf "Speculative." The following table sets out in addition to the Potential Gas Committee's estimate of the reserves for the total Gulf Coast and its breakdown between on and offshore, an estimate of potential reserves by State.

[6,768]

Potential Supply of Natural Gas
As of December 31, 1968—
Potential Gas Committee Report of October, 1969
Trillion Cublic Feet at 14.73 psia and 60°F

Reserves Classification	Total Gulf Coast [1]		
	Total	Offshore	Onshore
Probable	118	38	80
Possible	145	90	55
Speculative	28	19	9
Total Gulf Coast	286	142	144

Reserves Classification	Texas Gulf Coast		
	Total	Offshore [2]	Onshore
Probable	70	7	63
Possible	75	40	35
Speculative	9	6	3
Total Gulf Coast	154	53	101

Reserves Classification	Louisiana Gulf Coast		
	Total	Offshore [1]	Onshore [3]
Probable	43	26	17
Possible	70	50	20
Speculative	19	13	6
Total Gulf Coast	132	89	43

[1] As reported by the Potential Gas Committee I Table 3 of their report.

[2] Developed by subtracting Louisiana Offshore from Total Gulf Coast.

[3] Data obtained by oral communication.

[6,769]

Q. What are your conclusions in light of the above considerations?

A. First, I conclude that for the next several years the industry must rely primarily on domestic reserves rather than gas from foreign sources or gas manufactured from coal.

I further conclude that the volume of reserves remaining to be discovered in the Continental United States, and in Southern Louisiana, and particularly in the offshore area, are substantial.

I conclude that the public interest will best be served by providing a price structure which will encourage an expanded program of exploration and development of new reserves and which will provide the industry with needed capital to finance such an expanded program.

Having said this, however, the question arises as to whether or not the potential gas reserves in the Southern Louisiana area (although substantial) are sufficient to attain the level of new reserve additions required by the projected demand. In this regard, I again refer you to the Potential Gas Committee's potential gas reserve estimate for this area. It should be self evident that, although demand may require the finding on average of some 9 to 10 Tcf of new reserves per year through 1975 (See Table 2), in terms of potential gas supplies this goal may be optimistic. Nevertheless, it is my opinion that the effort should be made and to the extent that rates play a part, the recommended rates are

[6,770]

* * * *

Q. Can you quantify the volume of gas that will be forthcoming at any given price?

A. There is no way of knowing in advance the specific volume of gas reserves which will be discovered in the future. A number of factors determine the level of the exploration and drilling effort. These factors include the availability of prospects on which to drill, the availability of necessary equipment and labor, the availability of capital, and prices which are high enough to

[6,771]

encourage producers to undertake the search, with its attendant risks. If there is sufficient wildcat acreage under lease by the industry, and if there is sufficient equipment, labor, and capital available, then an increase in gas prices can be expected to have a direct, positive effect on the exploration effort, and the greater the price increase the greater will be the increase in the exploration effort, until there is full utilization of available equipment, labor, and capital. Beyond the point of full utilization of these resources, price increases for new supplies can be expected to have little effect.

Q. You mentioned increased price for new supplies. Can an increase in the price for flowing gas be expected to produce an increased exploration effort?

A. Cash flow from current gas sales provides the greatest source of capital by which the industry finances its exploration programs in search for new supplies. The evidence in the present record indicates that capital is now and will continue to be in the immediate future, in short supply in relation to the capital requirements necessary to overcome the current gas supply crisis (See Tr. 1465). Moreover, it appears that capital is the one essential resource which is most scarce, and the availability of capital will be a limiting factor in achieving a substantially increased exploration program.

Therefore, in making recommendations with respect to gas which has already been dedicated under long term contracts, I have given consideration to

[6,772]

this requirement by not only providing for the recoupment of incurred costs but also for contributing toward the capital requirement of an exploratory effort over and above historical levels.

Q. Does the industry have under lease in Southern Louisiana an adequate amount of acreage on which to explore for gas?

A. Yes. On December 15, 1970, a Federal wildcat sale was conducted involving 127 tracts in the western offshore Louisiana area. These tracts totaled 593,000 acres.

Of this, 543,898 acres was acquired by the industry at a total cost of almost $850 million dollars. This represents the largest investment ever made to acquire virgin acreage in a predominantly gas province. Also during 1970, the industry leased more than one million acres in West Feliciana, East Feliciana, St. Tammany and St. Helena Parishes. As of year-end 1969, the industry also held non-producing or unproven acreage in Southern Louisiana having a related gross investment of over $695 million dollars. This demonstrates that there is a tremendous amount of leased acreage available in Southern Louisiana for immediate gas prospecting.

Q. The court in *Austral* has suggested the need to estimate the future demand for gas. Have you made such an estimate?

A. No it was not necessary. Demand estimates were presented by witnesses Schantz, Lawrence and Clark

(See Table 1). I rely on the estimate of witness Schantz for purposes herein.

* * * *

[6,773]

A. Historically, the industry has discovered and marketed natural gas in sufficient quantities to meet demand except for recent periods. It would appear that the present gas supply shortage is such that the current demand for new gas is not being met, and in some instances gas distributors are not able to accept new gas service customers. It is possible that curtailment of service to existing customers may occur in the future should the gas supply situation not improve rather quickly. However, I would view such an occurrence as a temporary situation. There are a number of alternative sources of gas, both domestic and foreign. In time these sources will make up the difference between what is produced domestically in the field, and what is demanded. New investment in equipment and facilities for processing low sulphur oil are now being made, and increasing supplies of low sulphur oil will become available as a result. This will tend to reduce the pressure on gas from the standpoint of air pollution abatement. However, it is doubtful whether the domestic producing industry alone will ever again be able to find and produce sufficient volumes to meet the ever increasing requirements of the American market (Tr. 3834).

In these circumstances, the price for domestically produced gas should be established at levels which will result in increased exploration in the hope and the expectation that the shortfall in supply will be minimized during the period of transition to increased reliance on alternative sources of gas.

Such rates should, of course, be no higher than necessary

[6,774]

to accomplish this objective. More specifically, they should be at a level sufficient to provide the necessary incentive and capital for the efficient utilization of available resources in the search for a level of new reserve additions which from all available facts is possible of achieving in the Southern Louisiana area.

Q. Are you able to establish a desired level of service in terms of the volumes of new reserves which will be required?

A. Yes. I have shown the volumes of reserve additions which will be required in relation to the demand estimates shown on Table 1 for both the United States and Southern Louisiana. Please refer to Table 2. I have projected nationwide reserve additions of 24.6 Tcf on average for the period 1971-1975. This projection is based on a decline in the reserve production ratio to 10 to 1 by 1975. Southern Louisiana reserve additions are projected to range from 8.4 Tcf in 1971 to 10.7 Tcf in 1975 or an average of 9.7 Tcf for the 1971-1975 period. This average approximates the highest historical level of reserve additions reported for Southern Louisiana.

[6,775]

Q. How will the industry meet the capital requirements necessary to find and produce volumes of this magnitude?

A. Historically, the industry has financed its exploration and drilling programs primarily by means of internally generated funds rather than long term debt. This is true by virtue of the inherent risk of exploring

for hydrocarbons. In my opinion, the risks of exploration are increasing as the industry moves into more hostile environments such as are encountered in offshore operations. Thus, it does not appear likely that debt will contribute substantially to the industry's capital requirements in the future.

Q. Have you established vintages of gas for pricing purposes?

A. My rate recommendations cover all jurisdictional gas sales in the Southern Louisiana area, past and prospective. I have divided all such sales into two separate vintages for pricing purposes. The first vintage is comprised of all gas sold under contracts dated prior to October 1, 1968. The second vintage is comprised of all gas sold under contracts dated on or after October 1, 1968 (including other sales given special relief in Opinion No. 546-A).

Q. Please state your recommended rates.

A. I recommend a ceiling price of 22 cents per Mcf for first vintage gas, and 25 cents per Mcf for second vintage gas.

Q. When would such rates be collectable?

A. Immediately upon issuance by the Commission of its decision in these proceedings.

Q. How long would these rates remain in effect?

[6,776]

A. Until July 1, 1973, at which time the rates would increase to 23 cents per Mcf for first vintage gas and 26 cents per Mcf for second vintage gas. On July 1, 1975, the rates would be increased to 24 cents per Mcf for first vintage gas and 27 cents per Mcf for second vintage gas.

[6,776]

Testimony of Louis J. Engel

Q. What rates do you recommend for gas sales which have been made under first and second vintage contracts up to the date of the Commission's decision?

A. I do not make any specific rate recommendations with respect to such sales. It is, of course, not possible to increase retroactively the price for past sales. The principal question is whether the producers should be required to refund amounts previously collected for such sales. The requiring of refunds would have the effect of reducing prices for past sales below those actually collected. I have concluded that no refunds should be required. Implicit in this recommendation is my conclusion that revenues previously collected have not been excessive, and should be retained by the industry irrespective of whether such revenues were collected subject to refund. At a later point in my testimony I will discuss in more detail the basis for my conclusions in this regard.

Q. Please discuss the basis for your recommended rate of 25 cents per Mcf for future sales of second vintage gas.

A. The basis of such rate is the recent nationwide estimated cost of finding and producing non-associated gas as estimated by staff

[6,777]

witness Loring.

I recognize that it is not possible to determine the cost of gas with pinpoint accuracy. However, it is possible to determine a reasonable cost which may be considered representative for the period over which it is measured. I conclude that the cost of finding and producing non-associated gas for the most recent period for which data are available is approximately 25 cents per Mcf. This cost is generally applicable to the period 1965 through

1969, and is inclusive of Louisiana severance tax and gathering allowance. The components of the recent cost of gas well gas are set forth below. In developing these costs I have utilized a capital recovery period of 10.5 years instead of the 10 years used by witness Loring. This adjustment is required in light of the data reported by producer respondents to the time lag questionnaire in this proceeding.

1. Successful Well Costs	3.91
2. Lease Acquisition Costs	1.37
3. Other Production Facilities	0.88
4. Subtotal	6.16
5. Dry Hole Costs	2.12
6. Other Exploration Costs	1.81
7. Subtotal	3.93
8. Production Operating Expense	3.10
9. Return on Investment	8.41
10. Return on Working Capital	0.44
11. Net Liquid Credit	(3.89)
12. Regulatory Expense	0.17
13. Subtotal	18.32
14. Royalty at 15%	3.23
15. Subtotal at 14.65 psia	21.55
16. Subtotal at 15.025 psia	22.10
17. Area Gathering	0.51
18. Production Tax	2.30
19. Total	24.91

* * * *

[6,781]

* * * *

In my opinion the direct assignment method is reasonable, and I recommend it be adopted by the Commission.

Based on the foregoing, the components of the 1969 flowing gas well gas cost are as follows:

[6,782]

1.	Cash Expense	1.81
2.	DD&A	4.00
3.	Return at 13 Percent	5.46
4.	Total Production Cost	11.27
5.	E&D Expense	5.47
6.	E&D Return at 13 Percent	1.10
7.	Total E&D	6.57
8.	Total at 14.73 Psia	17.84
9.	Total at 15.025 Psia	18.20
10.	Gathering Cost	0.51
11.	Regulatory Expense	0.17
12.	Production Tax	2.30
13.	Total	21.18¢ per Mcf

Q. Do you consider this 1969 cost estimate as providing an adequate basis for determining the ceiling price for sales of first vintage gas as of the date of a Commission decision in these proceedings.

A. I do not believe that the flowing gas cost should be directly translated into a ceiling price for first vintage gas. The flowing gas cost methods tend to understate the required allowance for future exploration and development. In effect, the flowing gas cost is sufficient only to provide for the replacement, at historical cost levels, of each Mcf of gas which is produced.

For both Southern Louisiana and the Continental United States, replacement of production has fallen far short in 1969. In Southern Louisiana 4.2 Tcf of gas were found and 6.8 Tcf were produced. In the Continental United States 8.3 Tcf of gas were found compared with 20.6 Tcf of gas produced.

In view of the increasing demand for gas, and the demonstrated need to increase finding levels, it is necessary to provide an additional allowance for growth, so that each Mcf of gas produced and sold will

provide not only for the recoupment of incurred cost at historical levels, but also for the discovery of more than one Mcf in the future, at an increased cost per Mcf.

Based on the foregoing, I have adjusted the average cost of 21.2 cents per Mcf upward by an additional 0.8 cent per Mcf in arriving at my final recommended rate of 22 cents per Mcf. In doing so I considered the level of required findings in the future, the need for additional capital to underwrite the required exploration effort, and the anticipated increase in the cost of finding replacement gas in the future. I also considered the recent cost of 25 cents per Mcf. In the last analysis, however, this is a matter requiring the exercise of judgement.

Q. Please discuss the basis for your recommended ceiling price escalations.

A. In my opinion the cost of finding and producing natural gas has tended to increase over time. I expect this trend to continue in the future as the deeper horizons are explored and as exploration takes place on the more marginal prospects. Perhaps even more important is the effect of inflation. There has been a continuation of the trend of inflation in the general economy in recent years. Table 7 provides a measure of the effect of inflation on the gas producing industry. This table indicates that over the last 5 years, inflation has averaged about 4 percent per year. Based on a gas cost of 25 cents per Mcf, the effect of inflation at the rate of 4 percent for one year would be to increase

the cost of gas by 1 cent per Mcf. Stated another way, it would reduce the value of 25 cents of revenue to 24 cents in a one-year period.

The gas producer is particularly vulnerable to inflation since his gas sales are usually made pursuant to long term contracts of 20 years duration. For this reason most such contracts provide for several periodic or fixed price escalations during the life of the contract.

I conclude that it is necessary in the design of rates to make some provision for the anticipated increase in the cost of finding and producing gas.

I believe that the trend toward deeper drilling will continue. Since the cost of drilling increases with increasing depth, the per foot cost of drilling can be expected to increase in the future (See Table 6). I estimate that during the period 1970 through 1975, the average depth of gas wells and related dry holes will increase from approximately 6,000 to 8,000 feet. On this basis I estimate that the cost of drilling gas wells and related dry holes will be approximately $30 and $17 per foot respectively.

At the same time, I anticipate the productivity of drilling will increase. Implicit in my current cost estimate of 25 cents per Mcf is a productivity of drilling of 654 Mcf per foot of successful gas wells drilled. The experiences of recent years indicates this may be a somewhat conservative estimate for future. For the period 1964 through 1968, the productivity of drilling was

approximately 723 Mcf per foot drilled. This calculation excludes 1969 which in my opinion is atypical and

does not provide a guide to future productivity. On this basis, I estimate that for the period 1971 through 1975 productivity will average approximately 700 Mcf per foot.

I suggest one other adjustment with respect to dry holes. As the exploration effort increases, more marginal prospects will be drilled. This may be expected to result in an increase in dry holes. I estimate that each foot of successful gas well drilling will bear 1.1 foot of dry holes in the future, as compared with about one dry hole foot reflected in my estimate of recent cost. I also estimate that the future depletion period will be 18 years plus 1.5 year lag.

The effect of these adjustments is to increase the recent cost of 25 cents per Mcf to an anticipated cost of 26.68 cents per Mcf. My estimate of the future (1971-1975) cost of finding and producing non-associated gas is as follows:

[6,786]

	¢/Mcf
1. Successful Well Costs	4.29
2. Other Production Facilities	0.88
3. Lease Acquisition Cost	1.37
4. Subtotal	6.54
5. Dry Hole Expense	2.67
6. Other Exploratory Expense	1.81
7. Subtotal	4.48
8. Operating Expense	3.10
9. Return on Investment at 13% (10.5 years)	8.93
10. Return on Working Capital at 13%	0.45
11. Liquid Credit	(3.89)
12. Regulatory Expense	0.17
13. Subtotal	19.78

14.	Royalty at 15%	3.49
15.	Subtotal at 14.65 psia	23.27
16.	Subtotal at 15.025 psia	23.87
17.	Production Tax	2.30
18.	Gathering Cost	0.51
19.	Total	26.68

In light of the foregoing considerations I estimate that on a conservative basis, the cost of finding and producing gas can be expected to increase at the rate of approximately 3 percent per year. This reflects an anticipated increase in drilling cost and related dry holes and also takes into account the effect of inflation. Technological advances and economies of operation will tend to offset the effects of increasing cost to the extent they can be achieved. In order to allow for these and other possibly offsetting considerations, I have reduced the otherwise anticipated cost increase by 50 percent to 2.5 percent per year. This amounts to approximately ½ of one cent per year, or one cent

[6,787]

every two years. Further as the estimated anticipated cost of finding gas increases one cent every two years, the need for internally generated funds would increase commensurately. Thus this indicates an additional reason for providing first vintage gas price escalations.

Q. Please discuss your recommendations for sales of first and second vintage gas up to the date of the Commission's order in this proceeding.

A. Again, I believe costs should be the primary consideration. The flowing gas cost of 21.2 cents per Mcf discussed above is in my view most representative of the cost of gas which has already been produced, since it represents the cumulative cost experience of all produc-

ing gas properties in the accounting records of the industry for all years prior to and including 1969. Assuming the average gas property is productive for a period of at least 18 years this means that the cost experience of properties discovered and developed as early as 1951 are reflected in the 1969 test year data upon which the flowing gas cost is based. To this extent, the reported costs antedate the era of federal regulation.

The 21.2 cents per Mcf cost may be compared with the average aggregate revenue for all sales in Southern Louisiana of approximately 20 cents per Mcf. It thus appears that on an overall basis the collected rates were no higher than the reasonable finding and producing costs. I, therefore, conclude that the average of collected rates should be deemed reasonable and not excessive,

[6,788]

irrespective of the extent to which such revenues were collected subject to potential refund.

Q. Does this mean you are recommending a price of 21.2 cents per Mcf for all past sales?

A. No not at all. I have simply compared average flowing gas unit costs with average flowing gas unit revenues on an area wide basis, and as a result of that comparison I conclude that the revenues which were received by the industry for gas sales in the area were not excessive, and that such revenues should be retained for use in gas exploration and development by the industry irrespective of the rates collected by individual producers under individual contracts.

Q. If refunds are nevertheless required, how should they be determined?

A. Refunds should be determined by reference to those amounts collected in excess of 21.2 cents per Mcf under

first vintage contracts, and in excess of 25 cents per Mcf under second vintage contracts.

Q. Is there other evidence which would indicate that the revenue realized for past sales has not been excessive?

A. Yes. Reference to the data reported pursuant to the all areas questionnaire for test year 1962 indicates that the return earned by the producing industry on a nationwide basis for both oil and gas operations amounted to 13.6 percent in 1962, and that the return earned for gas in 1962 was 13.5 percent. It is important to recognize that these earning levels are based on gross revenues inclusive of any amounts received subject to potential refund.

This further serves to confirm the reasonableness of collected revenues, since the 1962 earning levels are in my view reasonable, and are consistent with the rate of return recommendations of the parties in these proceedings.

Q. What is your rate recommendation for casinghead gas sales?

A. I recommend that no distinction be made between casinghead and non-associated gas for pricing purposes.

The Btu content of casinghead gas is equal to or greater than that of non-associated gas, and it is therefore equally valuable as a fuel. To impose a lower price on casinghead gas would be to invite the diversion of such gas to the intrastate market. More importantly, there are substantial volumes of casinghead gas presently being flared in Southern Louisiana. These volumes amounted to 153 Bcf in 1968.

Since this casinghead gas is typically produced under low pressure conditions, it must be compressed in order

to be marketed. In many cases it is uneconomical at current prices to install the necessary compression facilities. In my judgement the rates which I recommend will justify the compression of a substantial portion of the casinghead gas now being vented, and will thus make such volumes available to the market.

Q. Is the cost of finding and producing casinghead gas the same as that of non-associated gas?

A. I have not attempted to determine the cost of casinghead gas. Any purported casinghead gas cost is inherently unreliable due

[6,790]

* * * *

Q. Is it reasonable to assume that the revenues which will be generated by your recommended rates will be utilized by the industry in the search for new gas reserves?

A. Yes, very definitely. The gas producing industry is in the business to stay. This is demonstrated by its continuing aggressive lease acquisition policy. As I noted earlier, only last December the industry paid approximately $850 million in a single Federal wildcat lease sale. Most importantly the acreage involved is expected to be productive primarily of gas.

Gas is an important source of revenue to the producer. According to questionnaire data, revenues from the sale of natural gas and related liquids accounted for approximately 35 percent of the respondents' total wellhead revenues in Southern Louisiana during 1969. Furthermore, available data reveals that the industry's revenues have historically been plowed back into further exploration, development, and production operations (See Table 5) but activity has declined (See Table 8).

Gas is even more important from the standpoint of its contribution to the nation's energy requirements. In 1969, for example, the respondents' gas and gas liquids production in Southern Louisiana accounted for more Btu's of energy than their

production of crude oil and casinghead gas. It is thus clear that natural gas is absolutely essential to both the producer and the consumer, and there can be no doubt that the industry will endeavor to maintain and increase its stake in this vital energy source.

Q. The Court in *Austral* has suggested the need to estimate the supply that the established rates will bring forth. Have you made such an estimate?

A. As I stated earlier it is difficult to predict with assurance the volume of reserves which will be discovered in the future in response to any given price due to the risks and uncertainties incident to the search for hydrocarbons. The rewards of drilling as measured by reserve additions tend to vary widely from year to year. For example, the productivity of gas wells has varied within the last few years from 841 Mcf per gas well foot drilled in 1967 to only 316 Mcf in 1969. It is therefore not possible simply to assume that if a certain amount of gas well gas footage is drilled a certain volume of reserves will be found. The level of new reserve findings will be determined in the final analysis by the extent of the exploration and drilling effort which takes place, and will depend on the success of that effort. However, it should be noted that an econometric model, which addresses itself to this problem, was presented by Witness Khazzoom.

Q. Is there reason to anticipate an increase in the exploration and drilling effort in Southern Louisiana?

A. Yes. I previously noted the large amount of acreage which the

industry has under lease in the area. The lease bonus and rental payments made to acquire and hold such acreage are substantial. Since such payments are for the most part lost unless exploration takes place within a specified period of time, and since undrilled lease holdings tie up large amounts of capital without any related return, there is a strong incentive for producers to proceed with exploration and drilling activities.

Q. The Court in *Austral* has suggested the need to assess the consequences of recommended rates on the industry. Will your recommended rates provide an incentive for producers to commit capital to the search for new reserves?

A. I have estimated that the cost of finding and producing gas will range from 25 to 27 cents per Mcf over the period 1971-1975, and I have recommended rates which will provide for the recoupment of such costs. These costs and related rates include a provision for return, or profit, at the rate of 13 percent on invested capital. I believe this return is sufficient to make the exploration for gas attractive relative to the industry's alternative investment opportunities.

Of course, there is no way to predict the action of individual companies as to the nature and extent of their response to my recommended rates. However in my judgment the rates I recommend will serve to make gas an attractive investment, and as such they should be expected to increase not only the level of the exploration effort, but also the number of companies participating in that effort. To

[6,793]

the extent additional companies are drawn into the search for gas, additional capital will be made available.

* * * *

[6,794]

* * * *

all likelihood the demand for gas will continue to run ahead of available supply.

Q. You made reference earlier in your testimony to the settlement proposal which has been filed in these proceedings. Do you propose to comment on the individual terms of the settlement?

A. No I do not. I believe the settlement must be evaluated in its entirety. Its terms appear to be mutually interdependent, and any modification of individual terms might well require the modification of other terms. This would lead to a rapid dissolution of the settlement.

Q. What is your overall opinion of the settlement?

[6,795]

A. I believe the settlement is reasonable, and in my judgement it is fully supported by the evidence in this proceeding. The settlement is consistent with my rate design, and I therefore support it as an alternative to my own independent recommendations.

Q. Does this conclude your testimony?

A. Yes.

* * * *

Testimony of Louis J. Engel

[6,798]

Table No. 3

Experienced Rate of Return
All Lease Types
Continental U.S.
Year 1962

Item Description	Amount (billion $) (a)
1) Cost of service before return	3.581
2) Total lease revenue	5.264
3) Excess revenue (Line 2—Line 1)	1.683
4) Total rate base	12.400
5) Rate of return (Line 3—Line 4)	13.6%

Source: Exhibits 49-J and 51-J in Docket Nos. AR64-1 and AR64-2.

[6,799]

Table No. 4

Experienced Rate of Return
Gas Well Gas Leases
Continental U.S.
Year 1962

Item Description	Amount (million $) (a)
1) Cost of service	576.7
2) Lease revenue	959.0
3) Revenue in excess of cost	382.3
4) Total rate base	2,837.3
5) Rate of return (Line 3—Line 4)	13.5%

Source: Exhibit Nos. 49-J, 55-J and 51-J in Docket Nos. AR64-1 and AR64-2.

* * * *

[6,825]

ADDITIONAL TESTIMONY OF ALBERT F. BASS

BEFORE THE FEDERAL POWER COMMISSION

IN THE MATTER OF

AREA RATE PROCEEDINGS
(SOUTHERN LOUISIANA AREA)

Docket Nos. AR61-2, *et al.*, AR69-1

Q. Are you the same Albert F. Bass who previously testified in the Docket No. AR69-1 proceeding at transcript pages 2306 through 2344, 5521 through 5558 and 5560 through 5680?

A. Yes.

Q. What is the purpose of your additional testimony in these proceedings?

A. I have been asked by the Associated Gas Distributors to evaluate the E & D component of the flowing gas cost study presented in this proceeding by the FPC Staff's witness Murr, which is based on the methods adopted by the Commission in Opinion 546.

Q. What conclusions have you reached as a result of your evaluation?

A. I conclude that an adjustment should be made to increase the E & D component in this study.

Q. What is the general basis for your conclusion?

A. My review of the E & D cost component presented here by

[6,826]

Mr. Murr indicates that, when stated on a comparable basis, this component is lower than the E & D cost allow-

ance adopted by the Commission in Opinion 546. In view of the changes which have occured within the industry between 1960 and 1969, i.e., between the test year used in Opinion 546 and the test year adopted in the Murr study, it is my opinion that the E & D component of an updated cost study should be at least as great as that found proper for the year 1960. It is also my opinion that an updated E & D allowance should be at least in line with the industry's exploration expenditures to revenues relationship in the year 1960.

Q. Why do you select the year 1960 for comparative purposes?

A. It is of course the test year utilized by the Commission in its findings in Opinion 546, and data so based have that sanction. More important however, this was a period when the level of E & D activity was apparently producing results which replaced the gas being produced and provided a margin which would permit the industry to grow. The cost base for rates in this proceeding should be on the same level.

Q. Would you explain how you compared Mr. Murr's E & D cost component with the E & D cost allowance in Opinion 546?

[6,827]

A. Mr. Murr shows a total E & D cost of 4.63 cents per Mcf (@ 14.73 psia) [Tr. 6338, Table 1, Column (b)], using a 13 per cent return and an economic factor of 2.5 for liquids and 1.0 for gas. When the E & D cost allowed in Opinion 546 (4.17 cents per Mcf) is converted to a 13 per cent return at a 14.73 psia pressure base and adjusted to an economic factor of 2.5, the resulting E & D cost allowance is 5.4 cents per Mcf, or .8 cents higher than that recommended by Mr. Murr. (See Appendix, Sheet 1).

[6,827]

Additional Testimony of Albert F. Bass

Q. Would you now give the adjustment factor you are recommending to "normalize" Staff witness Murr's E & D cost results?

A. I recommend that witness Murr's E & D expense element of 3.643 cents per Mcf be adjusted upward by 31 per cent. This would provide an E & D expense element of 4.772 cents per Mcf.

Q. Would you describe how you arrived at this 31 per cent adjustment figure and the sources of the data you employed?

A. I compared certain 1960 industry-wide exploration expenditure items as a percentage of 1960 gross wellhead values for crude oil and natural gas with the same elements as reported for the year 1969. (See Appendix, Sheet 2)

[6,828]

These data indicate that in 1960 these expenditure items as a percentage of gross wellhead value were 31 per cent higher than in 1969.

Two sources were used for the expenditure data: The Chase Manhattan Bank (CMB) data on *Capital Investments of the World Petroleum Industry* and the Joint Association Survey (JAS) data from their annual *Survey of the U.S. Oil and Gas Producing Industry, Section II, Expenditures and Receipts.* The source of the industry's gross wellhead value for crude oil and natural gas is data published by the U. S. Bureau of Mines.

Based on these data, the industry expended during 1960 between 16.02 per cent (CMB) and 17.55 per cent (JAS) of the gross wellhead value of their products for exploration expenditures. Using the same sources of data, the comparable figures for 1969 are 12.07 per cent (CMB) and 13.54 per cent (JAS). Taking an average of the percentages derived from these two sources one

arrives at 16.78 per cent for 1960 and 12.80 per cent for 1969. (See Appendix, Sheet 2) The industry's 1960 percentage is 31 per cent higher than the 1969 figure (16.78 ÷ 12.80 = 1.31).

Q. What adjustment would you make to the return component of Staff witness Murr's E & D allowance?

[6,829]

A. In addition to the rate of return adjustment recommended by the witness Murr, I recommend that this component also be increased by the same factor used in normalizing the expense component. The supporting data is not as clear cut, but I reason that if the allowance is structured to permit (and encourage) a level of E & D activity, as measured by expenditures, 31 per cent higher than that prevailing in the test year, the capital base which supports that level of activity should also be commensurately higher.

Q. What overall E & D allowance would this result in?

A. If we add 31 per cent to Mr. Murr's .987 cents return component, we increase this to 1.293 cents. As a result, the total normalized E & D allowance becomes 6.065 cents (4.772 + 1.293), which could be rounded for convenience to 6.1 cents per Mcf. This is the cost component for this element which I believe should be included in the cost on which flowing gas rates should be fixed, prospectively, in this proceeding.

[6,830]

APPENDIX
Sheet 1

CONVERSION OF OPINION 546 FLOWING GAS COSTS

Description	Opinion 546 [1]	Opinion 546 Adjusted
(1)	(2)	(3)
	Cents per Mcf (@ 14.65 psia)	Cents per Mcf (@ 14.73 psia)
Production Costs		
Cash Expense	1.93¢	1.94¢
D D and A	3.19	3.21
Return Allowance	5.71 [2]	6.22 [3]
Subtotal	10.83¢	11.37¢
E and D Expenses and Return		
Expenses	3.55¢	4.57¢
Return	0.62 [2]	0.85 [3]
Subtotal	4.17 [4]	5.42 [5]
Total	15.00¢	16.79¢

[1] Opinion 546, mimeo copy p. 83, and Appendix F, Columns (9) and (11).

[2] At 12 per cent rate of return.

[3] At 13 per cent rate of return.

[4] Using an economic modifier of 3.5:1; Opinion 546, Appendix F.

[5] Using an economic modifier of 2.5:1.

APPENDIX
Sheet 2

COMPARISON OF UNITED STATES EXPLORATION EXPENDITURES WITH GROSS WELLHEAD VALUE OF CRUDE OIL AND NATURAL GAS 1960 AND 1969

Year	U.S. Gross Wellhead Value	Exploration Expenditures		Ratio (2) ÷ (1)	Ratio (3) ÷ (1)
		CMB	JAS	CMB	JAS
	(1)	(2)	(3)	(4)	(5)
	Millions of Dollars			Per Cent	
1960	$ 9,209	$1,475	$1,616	16.02%	17.55%
1969	13,882	1,675	1,880	12.07	13.54

Sources: Col. (1): Year 1960, United States Bureau of Mines, *Minerals Yearbook*, Vol. II, pp. 317 and 362; Year 1969 data obtained from Bureau of Mines, *Mineral Industry Surveys*, "Natural Gas Production and Consumption: 1969," and "Crude Petroleum, Petroleum Products, and Natural-Gas-Liquids: 1969."

Col. (2): The Chase Manhattan Bank, *Capital Investments of the World Petroluem Industry*. Column (2) is the sum of Dry Holes, Geological and Geophysical Expense and Lease Rentals.

Col. (3): American Petroleum Institute, Independent Petroleum Association of America and Mid-Continent Oil and Gas Association, *Joint Association Survey of the U.S. Oil and Gas Producing Industry*, Section II: Expenditures and Receipts, 1964 and 1969; Tables I and II, respectively. Column (3) is the sum of Dry Holes; Geological and Geophysical Expense; Land, Leasing and Scouting Expenses; Lease Rentals; Exploration Overhead; and Other Exploration Expenses.

[6,833]

PREPARED TESTIMONY OF BAKER G. CLAY

Q. Please state your name and address.

A. My name is Baker G. Clay. My business address is 4 Gateway Center, Pittsburgh, Pa.

Q. What is your occupation?

A. I am a Senior Rate Engineer employed by Consolidated Natural Gas Service Company, Inc., a part of the Consolidated Natural-Gas System which distributes gas to consumers in Ohio, Pennsylvania and West Virginia and sells gas at wholesale in New York and Pennsylvania.

Q. What are your education and professional qualifications?

A. I was graduated from West Virigina University in 1958 with a Bachelors of Science degree in Mining Engineering—Petroleum Engineering option. Upon graduation, I accepted a position with Commonwealth Natural Gas Corporation where I was employed for one year as an engineer trainee. My duties with Commonwealth consisted of the maintenance and construction of transmission system properties. In 1959 I accepted the position of General Engineer in the pipeline rate department of the Bureau of Rates and Certificates, now the Bureau of Natural Gas, of the Federal Power Commission. I resigned my position with the Federal Power Commission in February, 1962 to join the Consolidated System.

[6,834]

Q. What were your duties with the Federal Power Commission?

A. My duties consisted of analyzing and preparing reports and memoranda on proposed changes in tariffs,

rate schedules and contracts filed with the Commission by natural gas pipeline companies. I assisted in the preparation of exhibits on classification and allocation of costs, design of rates, and related aspects of the rate-making process for use in pipeline rate proceedings and rate settlement conferences and provided technical assistance in rate proceedings. I also analyzed and provided technical assistance on the rate aspects of certificate proceedings for the construction of pipeline facilities subject to FPC jurisdiction.

Q. Are you a member of any professional organization?

A. I am a member of the Society of Petroleum Engineers of the AIME.

Q. What are your duties and responsibilities in your present position with the Service Company?

A. My primary responsibility since joining Consolidated in 1962 has been to represent the Consolidated System in connection with its participation in the area rate porceedings. In addition, I have participated in many studies involving our operating companies including the economics of proposed projects and the rate structures of these companies which includes transmission and distribution. I have also participated in the preparation of rate design evidence presented in the rate proceedings of these companies before both

the state commissions and the Federal Power Commission, and in rate and certificate proceedings involving Consolidated's pipeline suppliers.

Q. What experience have you had in the field of producer regulation?

[7,466]

TESTIMONY OF BAKER G. CLAY

• • • •

DIRECT EXAMINATION

BY MR. T. A. JONES:

Q. Would you please state your name and address.

A. My name is Baker G. Clay. My business address is Four Gateway Center, Pittsburgh, Pennsylvania.

Q. Does your prepared testimony in this case appear in the transcript commencing at page 6833?

A. Yes, sir, it does.

Q. Do you adopt that as your testimony in this case?

A. Yes, sir.

Q. Do you have any corrections to make to that testimony?

A. No, but I would like to insert some exhibit numbers in some blanks that appear throughout my testimony.

Q. Would you do that, please.

A. The first blank appears at transcript 6836, on line six. That should be Exhibit 90. On the same page, on line seven, that is Exhibit 93. The same page, line ten, that would be Exhibit 90.

As transcript 6838, at line seven, that should be

[7,467]

Exhibit 90.

At 6839, on line one, that should be Exhibit 90.

At 6841, at line twenty-five, that should be Exhibit 91.

At 6842, at line seven, that is Exhibit 90. And on line fourteen of the same page, that is Exhibit 90.

Transcript 6844, at line three, that should be Exhibit 91.

At 6846, line two, that should be Exhibit 91. And on the same page, line five, that is Exhibit 90. And on line twenty-one, that is Exhibit 91.

At transcript 6847, at line eighteen, that is Exhibit 90. At line twenty, that is Exhibit 91.

At transcript 6848, at line sixteen, that is Exhibit 91.

At transcript 6849, at line eleven, that is 92. At line thirteen, that is 93. And at line fourteen, again 93. And at line nineteen, that is Exhibit No. 92.

At transcript 6851, at line eight, that is Exhibit 91. And those are all of the blanks.

Q. Mr. Clay, were Exhibits 90 through 93 prepared under your direction and supervision?

A. Yes, sir, they were.

MR. T. A. JONES: Your Honor, subsequent to the service of this testimony and these exhibits we received requests for work papers underlying these exhibits. They have been distributed to counsel, and I understand that at least one party is using these work papers in the preparation of

[7,468]

rebuttal which would be served tomorrow. And I would like to offer these as an exhibit at this time so that they will be in the record for tomorrow's proceedings.

BY MR. T. A. JONES:

Q. Mr. Clay, I hand you a document which is entitled "Southern Louisiana Area Rate Proceeding. Work Papers of B. G. Clay in Connection with Exhibits 90-93."

Was this document prepared by you or under your direction and supervision?

A. Yes, sir, it was.

* * * *

MR. T. A. JONES: Your Honor, I offer Exhibits 90, 91, 92, 93 and 104 in evidence.

[7,496]

Testimony of Baker G. Clay

PRESIDING EXAMINER: I will admit 90, 91, 92, and 93.

* * * *

[7,496]

* * * *

Q. Mr. Clay, have you made any computation as to the refunds that would be due by producers under the UDC settlement proposal for the period October 1, 1968, to January 1, 1971? Limited to that period?

[7,497]

A. Under the UDC settlement proposal?

Q. Yes.

A. Yes, sir.

Q. If you have a dollar amount for that, would you read it into the record? Total?

A. Would you tell me the period again, please?

Q. October 1, 1968, to January 1, 1971.

A. I can give you the numbers that you could use to make the computation.

Q. If you would read them into the record, I think it would speed it up.

A. From October 1, 1968, through the end of the year, the—

Q. Which year?

A. October '68, through the end of the year of '68. One number is 5295. That is $5,295,000. You would add to that 21,405,000 for the year '69, 20,061,000 for the year 1970, and the total of those three numbers represents the total for the companies in my sample. If you divided that by .825 you would have the total for the industry for the period 10/1/68 through 1/1/70.

Q. Divided by what number?

A. .825.

* * * *

[7,498]

* * * *

A. The numbers I had available to me at the time I prepared this study I assume did include some post-10/1/68 gas. I doubt—and that would be for the year '69. It would by my understanding, though, that pursuant to Opinion 546, 546A, and the moratoriums that were laid down there, the end line rates that were established in that opinion, that there would be no refund on the post-10/1/68 gas.

Q. For which vintage?

A. Well, that would be the vintage—

* * * *

[7,499]

Q. Do you have a computation as to the refunds that would be due and owing under the UDC settlement proposal for the period after January 1, 1961?

A. Well, one problem I have with the question is I don't know when the Commission would approve the settlement. Assuming they approved it—well, I can give you an annual effect and then you can divide it by the number of months that transpire between January the 1st and—

Q. All right.

A. —the date of the approval of the order. $4,196,000.

Q. Per—

A. Year.

Q. Per year.

* * * *

[7,513]

Q. Please explain Exhibit No. 105 (BGC-5).

A. The first column lists the 20 producers having the most sales from Southern Louisiana under FPC gas rate schedules. The next column shows the annual volumes based on Staff Exhibit 45, i.e., 1968 actual volumes plus 12 times the volumes for the first month under new contracts certificated priod to 1/1/70 and for which there were no volumes in 1968. The next column shows total revenues for the volumes shown. This has been worked out on a rate schedule by rate schedule basis using rates proposed by Mobil. The last column shows revenue per Mcf that would be realized by each company based on Exhibit 45 volumes.

Q. Would any other of the 20 largest companies realize as much per Mcf as Mobil under its proposal?

A. No. The second highest average revenue would be produced by Superior at 23.48 cents per Mcf which is .25 cents less than the average revenue which would be realized by Mobil.

Q. Have you made studies showing the refunds that would result from the application of Mr. Knapp's proposed rates?

A. Yes. The total refunds would be approximately $132,076,000 for the industry through 1970.

Q. What would Mobil's refund obligation be?

A. My studies show that Mobil would have no refund obligation.

Q. What would be Mobil's refund obligation under the UDC proposed settlement?

A. Mobil's refunds would amount to $1,692,000 under the UDC proposal.

* * * *

Prepared Rebuttal Testimony of Celia Star Gody

[7,515]

PREPARED REBUTTAL TESTIMONY OF CELIA STAR GODY

Q. Please state your name and address.

A. My name is Celia Star Gody. My office address is 1101 Seventeenth Street, Northwest, Washington, D.C.

Q. Have you previously testified in these proceedings?

A. Yes. My prior prepared testimony appears at Tr. 1030-1044, Tr. 2083-2122, and Tr. 6003-6019.

Q. What is the purpose of your rebuttal testimony at this time?

A. To present, for the record, certain data which I believe are helpful in evaluating alternative rate design proposals. The data show the effect on producer revenues of several alternative rate designs, both in terms of average unit revenues and in terms of the range of company unit revenues under each of the assumed rate designs.

The witnesses who have presented rate design evidence have generally not accompanied that evidence with adequate information concerning the effect of the rate proposals on the revenues to be realized by gas producers. To illustrate, Staff Witness Engel makes only one brief reference to the approximate average price which would result from his recommended rates (Tr. 6793. Witness Wiskup presents a "rough approximation" of the difference between revenues at the prices proposed under the UDC Settlement Offer and at the prices established in Opinion No. 546

[7,516]

(Testimony, Tr. 6985; Exhibit No. 100, Table D), but he acknowledges that his estimate provides only a "general indication" of the amounts involved.

[7,516]

Prepared Rebuttal Testimony of Celia Star Gody

Witness Clay has presented some detailed data concerning the revenues which would be realized under the UDC Settlement Proposal. [Exhibit No. 90], but his detailed data cover only 23 major companies, while the information on range of company unit revenues which I am presenting covers 100 companies.

Q. Are you making any rate recommendations of your own?

A. No.

Q. Have you prepared an exhibit showing the range of company unit revenues under alternative rate designs?

A. Yes. It is Exhibit No. 106 (CSG-6), for identification. It was prepared under my supervision and direction.

Q. Please explain generally what is shown by the exhibit.

A. The exhibit shows the average unit revenues which would be realized for Southern Louisiana sales assuming alternatively the ceiling prices established

[7,517]

in Opinion No. 546, the ceiling prices contained in the UDC Settlement Offer, and single-ceiling prices ranging from 22 to 30 cents per Mcf. Additionally, the exhibit shows various measures of the range of company unit revenues under each assumed rate design.

The compilations in the exhibit cover all Southern Louisiana rate schedules under which deliveries were made in the year 1968 by companies which filed Form 301-B with the FPC. There were 100 such companies and their aggregate 1968 deliveries of Southern Louisiana gas amounted to 4,079 million Mcf.

Q. How did you proceed in compiling the information shown in your exhibit?

Prepared Rebuttal Testimony of Celia Star Gody

A. As was indicated in the testimony of Staff Witness Penix at Tr. 1123-24, in the spring of 1970 Foster Associates prepared a computer tape incorporating information for each Southern Louisiana rate schedule of companies filing Form 301-B for the year 1968. The tape included information on contract date, location (Federal Domain or Louisiana taxing jurisdiction), contract price, applicable price under Opinion No. 546, 1968 volume, and other relevant detail.

[7,518]

Information from this tape, after review by Staff and other parties, was submitted in evidence by Staff Witness Penix (Exhibit No. 45).

For the present study, a new tape was prepared with the following modifications:

(1) The applicable price under Opinion No. 546 for each rate schedule was modified where required to take account of contract price escalations through October 1, 1970.

(2) Where filings were made in accordance with Opinion No. 567 for gas from reservoirs discovered from January 1, 1961, to September 30, 1968, inclusive, the volume delivered under the rate schedule in 1968 was divided between gas from the old and the newly discovered reservoirs and the separate prices which would be applicable under the Opinion No. 546 price ceilings were assigned to each.

(3) The prices which would be applicable for each sale in accordance with the UDC Settlement Proposal were added to the tape, taking account of location and Btu content of the gas deliveries. The prices assigned were the lower of either the contract prices as of October 1, 1970, or the applicable settlement prices.

[7,519]

I had a computer program prepared to derive computations of the average unit revenue which would be realized by each company and by all 100 companies in total for 1968 deliveries assuming, alternatively, the Opinion No. 546 ceiling prices and the ceiling prices specified in the UDC Settlement Proposal.

Additionally, the computer program was designed to provide the applicable revenues for each sale at assumed single-ceiling prices ranging from 22 cents to 30 cents (again by reference to the lower of either the contract price as of October 1, 1970, or the assumed ceiling price) and the average revenue for each company and for all 100 companies in total under each assumed ceiling price.

Q. Will you now describe Chart 1 and Schedule 1 of your exhibit?

A. Yes. The red lines on the chart show the average unit revenues under each assumed rate design, derived in the manner I have just described. It is obvious from the chart and the supporting Schedule 1 that the average revenue falls short of the ceiling price under any rate design; the difference between the averag price and the ceiling price rises with increases in the ceiling price.

[7,520]

Chart 1 and Schdule 1 also provide an indication of the range of company unit revenues under each assumed rate design. For this purpose, the companies were arrayed from the lowest to highest unit revenue, separately for each assumed rate proposal. The range of unit revenues is shown on the chart, together with the median and quartiles determined by reference to aggregate company volumes. To illustrate, the median unit revenue under the UDC Settlement Proposal is 21.48 cents per Mcf; companies

with half of the total volume show average revenues lower than the 21.48 cents under the proposed settlement, and companies with half the volume show higher average unit revenues.

Q. What is shown by Chart 2 and Schedule 2?

A. The information is similar to that shown in Chart 1 and Schedule 1, except that the median and quartiles identified in Chart 2 and Schedule 2 were determined by reference to a count of companies. Thus, the median unit revenue under the UDC Settlement Proposal is shown here as 21.66 cents per Mcf; the meaning is that half of the companies show average unit revenues lower than the 21.66 cents assuming the proposed settlement and half the companies show higher average unit revenues.

[7,521]

Q. Do your compilations of average revenue reflect the prices which would be applicable for gas deliveries under contracts dated after October 1, 1968?

A. No. Inasmuch as all of my computations of average revenue were made using actual 1968 deliveries, the newest vintage sales are not reflected in the averages. There were no deliveries reported in Form 301-B for 1968 under contracts dated October 1, 1968, or later.

Q. Can you explain more specifically what interpretation should be attached to the figures for average unit revenues under the alternative rate designs?

A. The figures may be interpreted as showing the average unit revenues which would be realized as of October 1, 1970, for Southern Louisiana gas deliveries under contracts dated prior to October 1, 1968. Thus, the data provide a reasonably close estimate of the revenues under such contracts which would be realized at the present time under the assumed alternative rate designs.

[7,521]

Prepared Rebuttal Testimony of Celia Star Gody

Q. You said that the data provide a reasonably close estimate of the revenues which would be realized at the present time under the assumed alternative

[7,522]

rate designs. Do you have any indication of the extent to which the revenues from sales of gas under pre-October 1, 1968, contracts might have increased since October 1, 1970, as a result of contract escalations?

A. Yes. I recomputed the revenues at the single-ceiling prices, ranging from 22 cents to 30 cents, using as the point of reference the contract prices as of October 1, 1971, rather than the October 1, 1970, date which was used in the compilations shown in my exhibit. The effect of this change is to raise the average revenue by .05 cents at a 22-cent ceiling (from 21.15 cents to 21.20 cents per Mcf); by .15 cents at a 26-cent ceiling (from 22.84 cents to 22.99 cents per Mcf), and by .31 cents at a 30-cent ceiling (from 23.33 cents to 23.64 cents per Mcf).

Q. Have you prepared any estimates of the revenues which would be realized under the alternative rate design assumptions for all gas, including sales under contracts dated on and after October 1, 1968?

A. I have not had an opportunity, in the time available for the preparation of my exhibit, to make detailed computations of average revenues for sales under contracts dated on or after October 1, 1968.

[7,523]

However, I estimate that the inclusion of the newest-vintage gas would raise the average revenues for all sales by approximately one-half cent or less at ceiling prices up to 26 cents per Mcf.

* * * *

Rebuttal Testimony of David L. Knapp

[7,525]

REBUTTAL TESTIMONY OF DAVID L. KNAPP

Q. Please state your name and address.

A. David L. Knapp, Houston, Texas.

Q. Are you the same David L. Knapp who has previously testified in these proceedings,

A. Yes.

Q. What is the purpose of your additional testimony?

A. My purpose is to present rebuttal evidence to portions of the direct testimony of Federal Power Commission Staff Witness Louis J. Engel. His testimony is entitled "Rate Design and Recommendations" and appears in the record at Tr. 6763-6803, inclusive.

Q. What is the nature of your rebuttal testimony to Mr. Engel?

A. My rebuttal consists of two major parts, namely, (1) that the rates he recommends at Tr. 6775 for the future are based upon questionable evidence and conclusions, and (2) that his conclusions that the settlement proposal incorporated in these proceedings is "reasonable" and "fully supported by the evidence in this proceeding" (see Tr. 6794-95) are incorrect and without record support.

Q. What ceiling prices does Mr. Engel recommend?

A. Effective upon issuance by the Commission of its decision in these proceedings, Mr. Engel recommends a ceiling price of 22¢ per Mcf for deliveries under contracts dated prior to October 1, 1968 and 25¢ per Mcf for contracts dated on or after October 1, 1968. Further, he recommends increasing these ceilings one cent per Mcf on July 1, 1973 and an additional one cent per Mcf on July 1, 1975 (Tr. 6775-76).

[7,526]

He makes no specific recommendation for gas sales made prior to the date of the Commission's decision, but concludes that no refunds should be required (Tr. 6776).

Q. Do you disagree with this conclusion?

A. In the context of his rate design, I do. By concluding that no refunds should be required and by recommending a ceiling rate of only 22¢ per Mcf for these same contracts for the future, Mr. Engel is inconsistent. Producers who did not enter into company-wide settlements during the 1960's, for example, have collected rates well above 22¢ per Mcf in the past. Many other companies have not. (See Exhibit 45.) In effect, Mr. Engel is recommending higher ceilings for past periods than for the future.

Q. Do you agree with Mr. Engel's ceiling of 22¢ per Mcf for the future?

A. No, because it is too low to accomplish the objectives he gives for setting the price for flowing gas at Tr. 6771, namely, to generate capital to finance "exploration programs in the search for new supplies." He also states, "Moreover, it appears that capital is the one essential resource which is most scarce, and the availability of capital will be a limiting factor in achieving a substantially increased exploration program."

Further, I pointed out in my testimony at Tr. 6962-63, that based upon Mr. Auten's "Source and Disposition of Funds" study (Exhibit 64), ceiling prices of 23¢ and 24¢ per Mcf for offshore and onshore gas, respectively, must be viewed as bare minimums for

[7,527]

the future for contracts dated prior to October 1, 1968 in order to accomplish this objective.

Q. What are some of the problems associated with Mr. Engel's ceiling of 25¢ per Mcf for contracts dated after October 1, 1968?

A. The reasons Mr. Engel's ceiling price for this vintage of gas is too low are (1) he relies too heavily upon a single cost study with all of the defects inherent in such studies. These defects are summarized at Tr. 6946-47.

(2) He ignores the trend in estimated cost for the 1961-69 period. Dr. Sherwin provides such estimates for each year prepared on a consistent basis in Exhibit 63. Applying the cost increase to the 1961 guideline rate of 21.25¢ per Mcf, for example, results in an indicated price of 30.3¢ per Mcf for new sales in 1969 (see Tr. 6956-58); and

(3) Mr. Engel provides estimates for the effect of the rate of inflation for the future (Tr. 6783-84), but fails to take past inflation into account in setting ceiling rates for new gas. For example, he estimates that inflation has averaged 4 percent per year for the past 5 years, 1966-70, (Tr. 6783 and 6802). Assuming that his ceiling rate of 22¢ per Mcf is appropriate for new gas supplies in 1966, the ceiling price for 1971 would have to be approximately 27¢ per Mcf to account for inflation alone. His ceiling of 25¢ per Mcf would provide less incentive for exploratory drilling in 1971 than his 22¢ per Mcf ceiling in 1966.

Q. Do you have other questions concerning Mr. Engel's

conclusions regarding his 25¢ per Mcf ceiling?

A. At Tr. 6784, Mr. Engel "anticipates the productivity of drilling will increase." The effect of this "anticipation" is to reduce his cost estimate for new sup-

plies (1971-75) below estimates based on stable or declining productivity. At Tr. 6785, lines 7-8, Mr. Engel contradicts his "anticipation" by stating that "As the exploration effort increases, more marginal prospects will be drilled." Obviously if more marginal prospects are drilled, the assumption should be that the productivity of drilling will tend to decrease.

Mr. Engel's statement concerning productivity at Tr. 6791 provides a more accurate assessment of productivity, namely, that it is "not possible simply to assume that if a certain amount of gas well gas footage is drilled a certain volume of reserves will be found."

Mr. Engel conservatively estimates that "the cost of finding and producing gas can be expected to increase at the rate of approximately 5 percent per year" (Tr. 6782). This estimate is based in part upon an increase in productivity, or in other words, in technological advances and economies of operation. And yet, he reduces "the otherwise anticipated cost increase by 50 percent to 2.5 percent per year." The results are that Mr. Engel has reduced his future estimates twice for the same factor: first, by assuming increases in productivity that are unlikely to occur and second, by assuming that technology and economies will offset cost increases when technology and economies are the only bases for assuming increased productivity in the first instance.

[7,529]

Q. You stated that Mr. Engel's position regarding the UDC settlement proposal is incorrect. What are your reasons for this conclusion?

A. First, I assume that Mr. Engel's description of the UDC settlement proposal as "reasonable" is used in the economic sense that the terms of the proposal are

fair and equitable to consumers and to all segments of the industry, and that the ceiling rates and other provisions included in the proposal provide adequate incentive to maintain, in Mr. Engel's words, "adequate gas service by the producing industry to other segments of the gas industry" and "increase its gas prospecting and discover substantial volumes of new gas reserves" (Tr. 6764 and 6765).

Unfortunately, Mr. Engel does not provide an analysis of the UDC proposal, but simply states that "the settlement is consistent with my rate design, and I therefore support it as an alternative to my own independent recommendations" (Tr. 6795).

There are many very important differences between Mr. Engel's rate design and the UDC proposal, particularly with regard to refund calculations and disposition, periodic and contingent escalations, and term (period of applicability), so that the two are inconsistent in several key aspects. But the two proposals are similar in that neither meets the criterion of "reasonableness."

* * * *

[7,530]

* * * *

Q. What are your reasons for terming the ceiling prices in the UDC proposal inequitable and inadequate?

A. The ceiling prices, which would become effective on the first day of the calendar month following the issuance of the Commission's order incorporating the terms and conditions of the UDC proposal, are inadequate in the same sense as Mr. Engel's rate design.

The ceilings of 22.375¢ and 21.375¢ per Mcf, onshore and offshore, respectively, for deliveries under contracts dated prior to October 1, 1968 are completely inadequate

to generate capital in sufficient amounts to expand exploratory activities. Mr. Auten's study, previously referred to (Exhibit 64), based upon 1968 data, shows that average wellhead revenues nationwide must be increased over 5¢ per Mcf in order to provide the funds to expand exploration in any meaningful way.

* * * *

[7,533]

* * * *

Q. Do your reasons also apply to the periodic and contingent escalations contained in Section 3.3 of the UDC proposal?

A. Yes, the periodic escalations are inadequate to keep up with the rate of inflation forecast by Mr. Engel, even after Mr. Engel reduces the increased future cost of finding gas by 50% to account for technology and economies. They are even more inadequate if the cost of finding increases because of continuing inflation and declining productivity.

* * * *

[7,544]

TESTIMONY OF ALEXANDER E. WISKUP

earnings not paid out in dividends and therefore retained in the business. This internally generated capital comes from all of each company's sources, including the gas production in Southern Louisiana and represents Company-wide figures as shown in published sources. As can be seen, the total capital generated internally by these 14 large producers for the year 1969 was $5,793,373,000.

Q. Are some of these 14 gas producers subsidiaries of larger enterprises?

A. Yes, in those cases the parent's name is shown in parenthesis after the name of the producer. In such cases the figures are on a consolidated basis for the entire enterprise as shown in published sources.

Q. What is shown on Table B of this exhibit?

A. Table B shows the capital obtained externally by the same 14 large producers. Such capital comes from the sales of bonds, debentures, and common stock. Since large blocks of long term capital are usually obtained intermittently rather than on an annual basis, I have shown a tabulation for the ten years ending with the year 1969 and shown at the bottom the average per year. As is shown, the 14 producers obtained external capital on the average of $397,450,122 per year for this period.

Q. What is shown on Table C of this exhibit. Table C simply tabulates the cash and marketable securities that these 14 large producers had on hand as of Dec. 31, 1969. As can be seen, the total for

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[7,667]

TESTIMONY OF CELIA STAR GODY

* * * *

DIRECT EXAMINATION

BY MR. REBMAN:

Q. Please state your name and address for the record.

A. My name is Celia Star Gody. My office address is 1101 Seventeenth Street, Northwest, Washington, D.C.

A. Are you the same Celia Star Gody whose prepared direct testimony appears in the transcript of these proceedings at transcript page 7515 through 7523?

A. I am.

* * * *

[7,679]

* * * *

Q. Doesn't the UDC settlement propose a 26-cent per Mcf price for 10-1-68 contracts?

A. Yes, sir. But as I understand it, it is a ceiling price and that the UDC settlement does not propose to go above the contract prices where they may be below the ceiling.

[7,680]

Q. How many of the contract prices in the post-10-1-68 contracts have ceiling prices less than the area rate?

A. I would estimate that is in the neighborhood of

35 percent of the figure of 854.5, Mr. Morrow, for the reason that as I stated when I gave you these volume figures, of that 854.5 million Mcf, 308.1 million is gas which was committed under contracts dated prior to 10-1-68, but gas from reservoirs discovered subsequent to 10-1-68. Such gas is covered by the terms of the contract as originally written. Even though that gas is free to go up to whatever ceiling may be established for gas that is post-10-1-68, it is not going to go above the contract prices. The contract prices for this gas were not at 26 cents.

The contracts dated pre-10-1-68 under which this new reservoir gas was committed did not typically have area rate provisions. There is no basis for assuming that such gas would come in at 26 cents.

Q. All right. How about the 546 million under new contracts? Will you assume with me, or do you think it would be reasonable to assume with me that that would come in at 26 cents?

A. I think that is clearly an upper limit. I would agree that most of that would come in at 26 cents.

* * * *

[7,684]

* * * *

Q. All right.

Now, on Schedule 1 of your exhibit you show in the first two columns that the weighted average revenue under Opinion 546 rates was 18.63 and it was about 2.75 cents higher under the UDC settlement proposal.

Suppose you included the 854.5 million Mcf that relate to contracts post 10-1-68. To what extent would that raise the 21.38 cents that you shown for the UDC settlement proposal?

[7,684]

Testimony of Celia Star Gody

A. If I do that, Mr. Morrow, and also include the pre-10-1-68 contracts without deliveries in 1968, for

[7,685]

completeness, allowing all of the really new contracts dated post-10-1-68 to come in with a ceiling, I would get 21.96 cents per Mcf compared with the 21.38 cents shown for 1968 deliveries.

* * * *

[306,832]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2, *et al.*

AREA RATE PROCEEDING
SOUTHERN LOUISIANA AREA

SUPPLEMENTAL BRIEF ON EXCEPTIONS OF SHELL OIL COMPANY

OLIVER L. STONE
THOMAS G. JOHNSON
WILLIAM T. WISE
3969 R.C.A. Building
50 West 50th Street
New York, N. Y. 10020

[306,856]

7. The Examiner refused to give any weight to settlement rates previously approved by the Commission. In this respect the Examiner seems to have misconstrued the contention which we made to him.

We do not claim that prior settlement rates are inviolable. We do maintain they are entitled to weight in this area proceeding. At the very least, the settlement rates heretofore approved by the Commision constitute floors below which refunds cannot be ordered even if the Commission should conclude to order refunds below the last clean (certificated) rate.

We urge that rates approved in producer settlements approved by the Commission should not be reduced if such rates exceed within a range of reason the area ceiling rate determined for the gas covered thereby.*

By order issues August 1, 1962 in *Shell Oil Company*, Docket Nos. G-9446, *et al.*, the Commission approved a settlement affecting *inter alia* practically all of Shell's jurisdictional rates in Southern Louisiana. The Shell settlement was consummated after conclusion of prolonged hearings of a consolidated § 5(a) and § 4(e) rate proceeding involving all of Shell's jurisdictional rates which had been participated in by the Staff and numerous distributors. After the record was closed, Shell, Staff, and various distributors and some pipelines entered into settlement discussions which culminated in the settlement which was approved by the Commission's order of August 1, 1962. The contents of said order and the settlement agreement and petition for approval of said settle-

* Additionally, we maintain that in no event can refunds be ordered below any approved settlement rate as to any contract involved in a § 4(e) proceeding.

ment agreement, all of which constitute part of the Commission's files and records, are incorporated herein by reference.

[306,857]

Summarized as to its major aspects, all of which were agreed upon at the settlement conferences in the light of the extensive evidence including several cost-of-service studies relating to Shell, the settlement obligated Shell to and Shell actually did:

1. Reduce substantially a number of firm contract prices which had been theretofore permanently certificated by the Commision;
2. Reduce substantially a number of rate increases which were then pending in § 4(e) rate increase proceedings;
3. Refund in excess of $8 million, plus interest;
4. Fix a moratorium on rate increases and thus forego contractually authorized increases until January 1, 1965 as to many of the settled rates, and until July 31, 1972 as to 12 large volume contracts covering Southern Louisiana gas.

The Commission is aware that since the early 1960's it has encouraged the settlement of producer rate cases. A condition to the approval of producer settlements was that the settled rates be within the range of reasonableness. In its 1963 Annual Report the Commission states (p. 120):

> "One of the outstanding achievements in producer regulation during the year was the implementation of an active program for the settlement of the outstanding rate suspension and certificate proceedings.

> The program included overall settlements involving a majority of the rate schedules of individual major producers . . . ."

And (*Id.* at 121):

> "Refunds under the overall settlements were determined on a cost of service basis and generally started from a date when the average unit revenues collected began to equal the average unit cost of service."

From the Shell settlement agreement, and the myriad rate downward adjustments embodied therein and the obligations imposed upon Shell thereby—all of which have been and are being complied with—together with the fact that the settlement was reached in the light of a fully developed evidentiary record including cost-of-service studies and a full range of economic and market data, it is apparent that the settlement reflects a multitude of factors carefully bargained out, and fully supported by appropriate considerations which cannot possibly be meaningfully evaluated in a group proceeding such as this. Such results, particularly when, as in this instance, they have been carefully scrutinized and approved by the Commission in light of a policy requiring the settlement rates to fall within the range of reasonableness, should not be lightly cast aside on the basis of results reached on a group basis in an area proceeding. Nor should the rates established and approved by such settlement be reduced in the event they exceed within a range of reason, say, 10%, the ceiling rate determined herein for flowing gas. That is, if the total dollars of revenue Shell would have received at the settlement approved rates for the year

1966 under all of its Southern Louisiana rate schedules involved in the Shell settlement exceeds by 10% or less the total dollars of revenue which would have been forthcoming from those same volumes and rate schedules for that same period at the ceiling price determined herein for flowing gas, then in that event the Shell rate settlement rates shall remain in force unaffected by the outcome of this proceeding.* In the event the total revenues so computed exceed by more than 10% the revenues calculatd at the flowing gas

[306,859]

ceiling price established herein, such revenues shall be reduced to the 10% level by making proportionate or pro rata reductions in those rates which exceed the flowing gas ceiling price by more than 10%.

In the absence of an appropriate recognition of settlement rates along the above lines, Shell and other producers who have participated in the effectuation of the Commission's policy of stability of producer rates through settlements, will be penalized for having done so. They have already suffered the obligations imposed by their settlements. They have already, for several years past, reduced firm rates which could not have been reduced other than by the conclusion of a § 5(a) proceeding affecting those rates. They have already reduced rate increases and have refunded large amounts of money. They have already foregone and are continuing to forego the right to file contractually authorized rate increases because of the moratorium periods included in the settle-

* Such rates shall then constitute floors below which refunds will not be payable, in the event refunds are applicable to any of such rates or rate schedules.

ments. While it is difficult to place a precise dollar and cents value on the rights which have been surrendered and the obligations incurred by virtue of the settlements, it seems obvious that it is significant. At any rate, it is clearly of such substantiality that, we submit, it would be unfair and discriminatory not to give special recognition, implemented along the lines recommended above, to the Shell settlement in the design of rates in this proceeding, and we respectfully urge that such consideration be given.

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* * * *

[307,822]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2, *et al.*

IN THE MATTER OF:

AREA RATE PROCEEDING, *et al.*
(SOUTHERN LOUISIANA AREA)

ANSWER OF SHELL OIL COMPANY IN OPPOSITION TO PETITION BY TEXACO INC., *ET AL.* FOR PROMULGATION OF SETTLEMENT PROPOSAL

Shell Oil Company (Shell), pursuant to § 1.9 of the Commission's Rules of Practice and Procedure, files this answer in opposition to "Petition For Promulgation Of Settlement Proposal" filed herein by Texaco Inc., *et al.* and, for the reasons hereinafter set forth, urges the Commission to deny the petition and to reject the settlement proposal submitted therewith.

I.

Pursuant to the requirements of said § 1.9, Shell admits the allegations of fact contained in the petition but denies the conclusions drawn therefrom by petitioners; and Shell specifically denies that it would be in the public interest or that of Shell for the Commission to approve or promulgate the proposed settlement. To the contrary, the proposed settlement is unduly discriminatory, preferential, and inequitable and its approval would be contrary to the public interest and to Shell's interest; would not be in the public convenience and necessity; and would seriously aggrieve Shell.

II.

In support of this opposition it is respectfully shown:

A. *Background and Shell's Interest.*

1. Shell is a respondent in this proceeding and, in cooperation with a group of producer-respondents, has actively participated in the preparation

of evidence, hearings, briefings, and arguments. Shell has also actively participated, cooperatively with a group of producers, in prolonged discussions with other parties at interest, seeking to reach a reasonable and equitable settlement of this proceeding, but its efforts in that respect have been in vain.

2. Shell has been one of the pioneers in the search for oil and natural gas in south Louisiana, including the offshore area; * and continues to be, as it has been for many years, actively and extensively engaged in the search for, development, production and sale of natural gas in this area. As a result of its active interest and heavy commitments in south Louisiana, Shell holds extensive natural gas leasehold interests and large reserves of natural gas in south Louisiana, and probably holds more acreage under oil and gas lease in the outer Continental Shelf off Louisiana than any other producer.

Shell's early successes in discovering major reserves of natural gas in south Louisiana have been followed by the practice of prompt commitment of its gas reserves to the interstate market. As a direct result thereof, an exceptionally high percentage of Shell's interstate natural gas

* The expression "south Louisiana" is used herein as including offshore as well as onshore.

deliveries in this area, in excess of 80 percent as of January 1, 1965, are pursuant to contracts with initial delivery dates prior to 1961, and virtually all of these contracts are dated subsequent to June 7, 1954.

Evidence of record in this proceeding (Exhibit No. 64-A, Schedule 3, Revised) reflects that for the 1960 test year herein (and for 1961) Shell was first in volume among all sellers of south Louisiana gas then being delivered in interstate commerce.

[307,824]

Shell thus has a substantial stake in this proceeding and is vitally concerned with any order which may be issued or action taken herein by the Commission, including action which the Commision may take on the Texaco, *et al.* petition.

Although Shell actively participated in settlement discussions with the view toward compromising and settling the issues involved in this proceeding, it has not joined in nor is it a party to the proposed settlement which the Texaco, *et al.* petition seeks to have the Commission promulgate. Despite Shell's refusal to join in, adopt, or in any wise to approve the said proposed settlement, any order by the Commision approving or "promulgating" said proposed settlement as being in the public interest, or as embodying just and reasonable rates, or rates compatible with the public convenience and necessity, while not technically binding on Shell, will, as a practical matter, substantially and adversely affect and aggrieve Shell.*

Approving or "promulgating" the proposed settlement by the Commission will not obviate the legal necessity of

* In the response filed herein by Philadelphia Gas Works it is urged (pp. 4-5) that as to non-settling parties, "all the features of the settlement" should accompany any future certificates issued to them.

the Commission rendering a decision herein on the merits and on the basis of the applicable law and evidence, as to non-settling parties. Yet it would be less than realistic to suppose that, once having approved or promulgated the proposed settlement as being in the public interest, the Commission could or would decide the issues in this proceeding as to the non-joining parties strictly on the basis of the applicable law and evidence without being significantly influenced by its previous action on the settlement proposal. We believe it inevitable that it would be. Actually, the fixing of different rates, moratoria, and conditions of sale for those who wish to settle and those who do not, would undercut the foundation of the area rate

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approach and would be at odds with its basic premise which is to fix uniform prices for gas applicable to all producers in a given area, rather than to establish individual and different prices for each producer.

We submit, therefore, that approval by the Commission of the proposed settlement will not only make a shambles of the administrative process, thus generally affecting Shell, but it will have a direct and adverse effect upon and will seriously aggrieve Shell. Therefore, Shell has full standing to interpose this opposition.

B. *The Proposed Settlement is Not in the Public Interest, and Its Adoption Will Result in a System of Unduly Discriminatory and Preferential Rates and Contract Conditions in South Louisiana.*

1. The settlement proposal is not in the public interest because the proposed rates, moratoria and other terms and provisions thereof are so burdensome, onerous, and unjust as to a substantial segment of the natural gas

producing industry in south Louisiana that it will substantially stifle incentive to search for, develop and produce new gas in south Louisiana, and will force the premature abandonment of currently producing gas horizons, thus deterring the required effort to bring forth the maximum natural gas supplies from the most potentially prolific gas producing area in the country; and one from which major consuming areas are dependent for the bulk of their present and future gas supplies.

2. The proposed settlement discriminates against the south Louisiana area, and will thus force the gas finding and production effort away from the country's most promising area for gas supplies.

The Commission is, of course, aware of the guideline and in line prices, and the other differentials existing in south Louisiana and in the Permian Basin; and the just and reasonable prices and moratoria established in its Opinion 468 in Permian Basin. The proposed settlement, viewed in the light of a comparison of the relevant factors in these two areas, will discriminate against the south

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Louisiana area. This is clearly shown in the *amicus curiae* brief filed herein by the State of Louisiana. That brief cogently demonstrates that for pre-1961 gas a price of less than 19.8 cents per Mcf and for post-1960 gas a price of less than 21.75 cents per Mcf will clearly discriminate against south Louisiana as compared with Permian Basin. It is noteworthy that the discrimination would occur assuming similar moratoria periods in the respective areas. Considering the much longer moratoria periods embodied in the proposed settlement, it is apparent that the discrimination against south Louisiana will be more pronounced if the instant proposal is approved.

3. The proposed settlement is unduly discriminatory in price and other terms and conditions against various categories of gas and the producer-sellers of that gas; and the proposed settlement grants unduly preferential treatment to certain categories of gas and the producer-sellers of that gas.

(a) At the outset it must be observed that there is no evidentiary support for the three vintages or time periods into which the proposed settlement categorizes the settlement price groupings. This is particularly true for the period on or after January 1, 1965.

(b) The proposed settlement unduly discriminates in price and other terms and conditions against gas committed to the interstate market prior to January 1, 1961, and the sellers of that gas; and unduly discriminates against sellers of pre-1961 gas whose last firm rate happens to be below 20.25 cents per Mcf but who are contractually entitled to a price at or above 20.25 cents per Mcf. There is no supportable basis in law, in the record evidence, or in equity or fairness for this unjustifiable difference of treatment of like sellers of like gas.

The settlement proposal deals thus with the price of pre-1961 onshore gas, assuming contractual entitlement in each instance:

The floor is 18.75 cents per Mcf.
The ceiling is 20.25 cents per Mcf.

The *sole* criterion for exceeding the floor is "last firm rate" entitlement; with complete disregard of contractual entitlement above the floor, although in the eyes of the law one is just as "just and reasonable" or as much in

the "public interest" as the other. Therefore, the mere happenstance of one seller having received a certificate price or prior individual company settlement price of, say, 20.5 cents entitles him to receive preferential treatment to a price of 20.25 cents per Mcf as against another seller of comparable gas, who, because of the timing of his sale of like gas, had a contractual entitlement price of, say, 21.5 cents per Mcf, but had to take a "last firm rate" of 18.5 cents per Mcf. This latter seller is saddled with the 18.5 cents price even though his contract entitles him to receive 21.5 cents and he may have filed an increase to that level and is collecting it subject to refund under a § 4(e) proceeding.

The "last firm rate" preference to some producer-sellers and undue discrimination against others, as it is embodied in the settlement proposal, finds no justification in law, or the evidence, or in equity. It is discrimination pure and simple. A "just and reasonable" or "public interest" price is in no way dependent upon whether it was a "last firm price".* To attach that condition to above-floor entitlement for pre-1961 gas is but to impose a meaningless distinction of nomenclature in order to grant preferential treatment to some sellers of gas, and their royalty owners, and to unduly discriminate against other sellers of gas similarly situated, and their royalty owners.

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A rate is either "just and reasonable" (or in the "public interest") or it is not. When different producer-sellers have contractual entitlement to the same price, it is clearly unduly discriminatory against some and preferen-

* "Last firm price" has significance as a floor for refund purposes. It has no significance, as such, in the applicability of a "just and reasonable" or "public interest" price.

tial to others, to utilize the happenstance of "last firm rate" as a vehicle to enable some sellers to receive a higher price than others. "Last firm rate" is but an interim device to maintain a firm level until a just and reasonable area rate can be determined under § 5(a). That was the stated purpose of this proceeding. To give to that interim device, as the settlement proposal purports to do, a greater dignity and entitlement than other contractually authorized prices, is to champion form over substance, an impermissible approach when, as here, it results in undue discrimination.

If this matter goes to Commission decision (and we urge that it do so), the Commission will establish just and reasonable rates which will apply uniformly to similar gas, perhaps with "old" and "new" gas categories, but without regard to whether or not a given contractually authorized price happens to be the "last firm rate". That is what the Commission did in the Permian Basin case. Obviously, a difference of treatment in a Commission order on the sole basis of a rate being "last firm" renders the order invalid on the basis of undue discrimination and preference. The same underlying principle would apply here if the Commission were to approved the proposed settlement. And that principle may legally be invoked by one who will be aggrieved by the order (as Shell here), although he is not a party to the petition seeking approval of the proposal, because it is inevitable that the approval of the settlement will have an adverse impact on Shell's rights when the Commission comes, as it must, to issuing a decision herein on the merits and based upon the applicable law and evidence establishing just and reasonable rates for south Louisiana.

The proposed settlement clearly recognizes that a price of 20.25 cents for onshore pre-1961 gas is in the public interest. We have no disagreement with that premise, as such. But one of the serious deficiencies of the proposal is its denial of entitlement to that public interest price to those, like Shell, who have equal legal entitlement to it, but are foreclosed from receiving it on the whimsical basis that their contractually authorized prices are not "last firm".

(c) The moratorium applicable to pre-1961 gas is unduly discriminatory and is not in the public interest.

The settlement proposal provides that, as to pre-1961 onshore gas, "*if the primary term of the contract expires before January 1, 1978*" (p. 1, underscoring added), the seller, if his contract permits, may, on or after January 1, 1973, file a rate increase to 20.25 cents per Mcf. However, "*if the primary term of the contract has not expired prior to January 1, 1978*" (p. 2), the seller is prohibited from filing a rate increase until January 1, 1978, and at that date he can only file for a 1 cent increase which may hold him below 20.25 cents even though his contract would entitle him to a price substantially in excess of 20.25 cents. The proposed settlement does not attempt to explain, nor could it have reasonably done so, the reason for this rank discrimination against and penalty imposed upon producers who may have entered into 20-year contracts in 1958 or thereafter and in favor of those who may have entered into similar contracts for 20 years in 1957 or years prior thereto.

Suppose that producer "A" sold his onshore gas under a 20-year contract dated in 1952 at a total price of 18.75 cents with 1 cent increases each 5 years. Producer "B" sold his gas under a 20-year contract dated in 1959 at

a price of 23 cents and received a certificate in, say, 1962 at 18.75 cents. Since A's

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contract primary term expires prior to January 1, 1978, he can file to 20.25 cents on January 1, 1973; whereas, since B's contract term does not expire prior to January 1, 1978, he must wait until January 1, 1978 and then he can only file for a 1 cent increase, making his total price 19.75 cents. At that date, however, producer A can then add on another cent to his 20.25 cents price, so that on January 1, 1978 A will get 21.25 cents and B will get 19.75 cents. Any approach which leads to such absurdities and such rank discrimination should certainly not commend itself to Commission endorsement.

And the matter is not of mere academic interest to Shell, because of the following:

In or about 1949 Shell committed to interstate sales large reserves of south Louisiana gas under several 10 year contracts. In 1959 new 20 year contracts replaced the expiring contracts. These 1959 contracts (with initial tax inclusive contract prices of about 23.55 cents per Mcf) were treated by the Commission as "changes" and the rates therein were suspended under § 4(e). In 1962, in keeping with the then Commission policy encouraging settlement of individual producer rate cases, these sales were settled at 18.5 cents per Mcf with a moratorium until 1972 subject to certain contingencies. Under the proposed settlement the prices in these contracts will remain firm at 18.75 cents until 1978, since the primary terms do not expire prior to January 1, 1978. This means that these prices will have been frozen (but for the ¼ cent difference between 18.5 cents and 18.75 cents) *for more than 16 years* and at the end of that prolonged

period the prices may not even then go up to the pre-1961 ceiling of 20.25 cents in the proposed settlement, but may only be increased by 1 cent, or to a total price of 19.75 cents.

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Contrasted to Shell's situation, many other producers with contract terms expiring prior to January 1, 1978, may by that date be entitled to 21.25 cents as against Shell's 19.75 cents price, although Shell has contractual entitlement to a price in excess of 21.25 cents. This, among the other discriminatory features of the proposal, should serve to allay any doubts as to the motivations prompting this opposition.

Further illustrations of the unduly discriminatory, preferential and inequitable aspects of the proposed settlement are available (such as the discriminatory treatment against new producing zones or horizons discovered under existing contracts prior to the effective date of the settlement, as is evident in Article IV, A) but with this final observation we leave the matter: The moratorium periods themselves differ for the several vintage periods. Accordingly, pre-1961 sales are subject to a longer moratorium under certain circumstances than those of the 1961-1964 inclusive vintage period, both of which in turn are subject to a longer moratorium than the post-1964 sales. No attempt is made to justify or rationalize these differences in treatment. The reason, we suggest, is that none exists or can be reasonable formulated.

III.

Shell has actively participated in numerous settlement conferences in a good faith attempt to reach a fair settlement of this proceeding. Our opposition to the proposal

is therefore based not upon any aversion to settlement, but rather upon the conviction, as heretofore demonstrated, that the instant proposal is discriminatory in substantial aspects which will seriously adversely affect Shell and other producers who may be similarly situated and that the proposal is not in the public interest.

[307,832]

Should the settlement proposal be altered to remove its discriminatory and unfair aspects Shell would willingly reevaluate its position, or should the Commission reject the proposal leaving open the avenue of further settlement discussions, Shell would then, as it has throughout the prior discussions, participate therein with the view to reaching a fair accord. In its present content, however, and for all of the foregoing reasons, the proposed settlement is not in the public interest and will seriously aggrieve Shell, and we urge the Commission to deny the petition seeking its promulgation and to reject the proposed settlement.

Respectfully submitted,

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